Peak Heat WP5: Cost benefit analysis

Peak Heat Project

Western Power Distribution
FINAL

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Contents

Executive summary

WP5 of the Peak Heat project assessed the high level cost benefit analysis of incentivising heat flexibility solutions under several scenarios within Peak Heat. It also brings together key findings from across all five work packages and makes recommendations for WPD.

The objective was to determine the most cost effective heat flexibility options for WPD when comparing these against the cost of upgrading the LV network, and as such inform WPD's approach to domestic heat and flexibility. It should be noted network upgrades required to support electric vehicle (EV) charging were not considered in this analysis.

Flexibility measures were selected for cost analysis based on scenarios explored in WP4 where most distribution substations were overloaded under high heat pump uptake during 1-in-20 cold weather conditions. The scenarios selected under these conditions were:

1. Business as usual ('BAU') – the "do minimum" or traditional reinforcement scenario
2. Hot water flexibility – homes with heat pumps allow flexible hot water generation
3. Temperature flexibility – homes with heat pumps allow more flexible indoor temperatures
4. Buffer tank flexibility – homes with heat pumps also have buffer tanks and provide this capacity for peak reduction benefits
5. Battery flexibility – half the homes with heat pumps also have electrical battery storage and provide this capacity for peak reduction benefits

Costs were made up of the incentives required to implement flexibility measures as well as the costs for reinforcement. Two network reinforcement scenarios were tested: in the first scenario distribution substations are upgraded to the next largest rating as and when necessary, meaning that multiple upgrades over the 30 year period were required in some instances; in the second (more likely) scenario substations were only upgraded once, with the upgraded ratings chosen to meet forecast demand in 2050. Benefits consisted of the capacity released by each measure to defer reinforcement of the network. These costs and benefits were calculated for each distribution substation under the three primary substations chosen for analysis in previous work packages, for each of scenarios 1 – 5 for every year up to 2050. Scaling factors based on heat pump uptake were used to extrapolate these costs and benefits up to the wider WPD network and GB-levels. The methodology to determine the NPV of each scenario is summarised in the figure below:

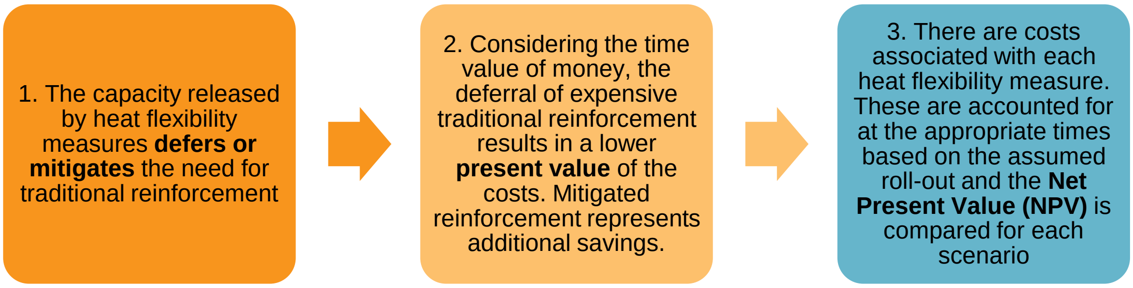

Figure 1. Overall process followed to determine NPV for flexibility scenarios

Figure 2 shows the cumulative cost of each scenario for the three primary substations under study in net present value (NPV) terms. The baseline costs of the pre-emptive reinforcement scenario are higher initially compared to the multiple reinforcement scenario, but lower overall in NPV terms after 2043.

Temperature and hot water flexibility only provide a relatively small reduction in demand, but this still enables upgrades to be deferred by a few years and reduces costs overall. The same applies to use of flexibility from buffer tanks. Use of storage capacity from electrical batteries can delay upgrades by several years, resulting in quite significant cost savings compared to the baseline.

Whether or not flexibility measures are more cost effective than network upgrades depends on the costs assumed for upgrades versus flexibility measures. While the assumptions used in this analysis are based on the best information available at present, it is noted that the costs of flexibility measures are highly uncertain.

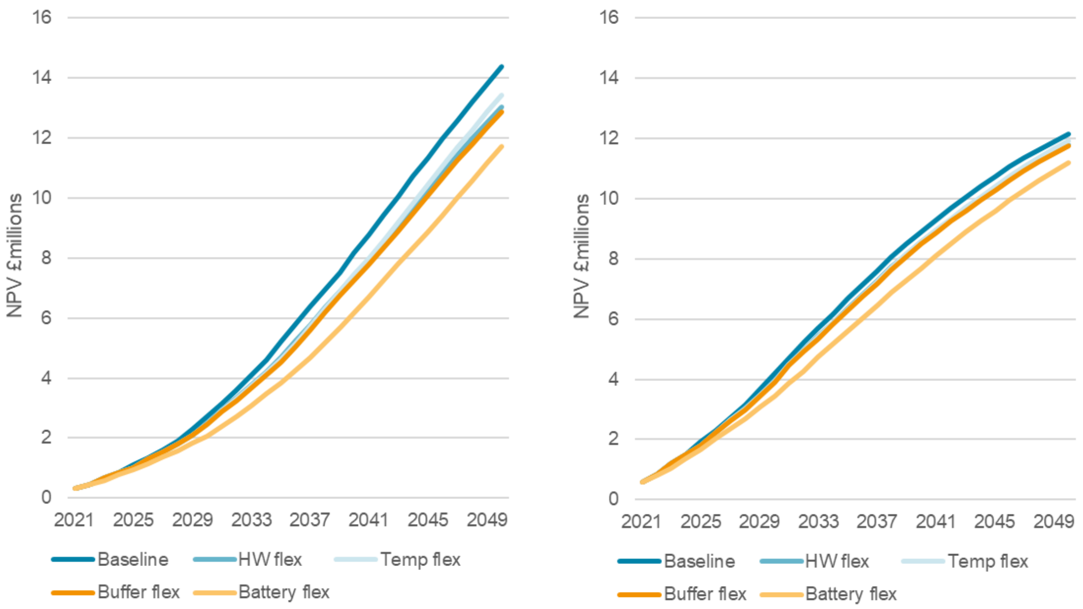

Figure 2. NPV (£millions) for each scenario at the 3 primary substations level, allowing for multiple distribution upgrades (left) and assuming pre-emptive reinforcement to have only single distribution upgrades (right) between 2020-2050

Table 1 on the following page shows the net cost savings of the different flexibility scenarios relative to the baseline for the three primaries under study, the full WPD network, and the whole of GB. It assumed that pre-emptive reinforcements are made. These results indicate that widespread use of demand side flexibility measures could potentially save WPD hundreds of millions of pounds in reinforcement costs by 2050.

Uptake of flexibility measures will be lower in reality than the illustrative 100% uptake levels used in these scenarios (or 50% in the case of electrical batteries), so savings would be lower in practice, likely in the order of tens of millions of pounds, though the exact figure will ultimately depend on how strongly households are incentivised to provide demand response. The values in Table 1 are also based on the conservative assumption that substations are upgraded at 90% of their continuous rated capacity. In practice these upgrades could potentially be delayed, in which case the value of the various flexibility measures would be less.

Table 1. Cumulative net present value (£m) of Peak Heat flexibility measures compared to traditional reinforcement case at the three primary scale, WPD and GB-scale (rounded) – negative values indicate a net benefit of using flexibility measures compared to traditional reinforcement

Scenario	Scale	2030	2040	2050
Hot water flexibility	Three primary	-£0.2	-£0.3	-£0.4
	WPD	-£36	-£54	-£55
	GB	-£96	-£260	-£248
Temperature flexibility*	Three primary	-£0.3	-£0.3	-£0.2
	WPD	-£43	-£51	-£36
	GB	-£115	-£242	-£160
Buffer tank flexibility*	Three primary	-£0.3	-£0.4	-£0.4
	WPD	-£46	-£64	-£60
	GB	-£123	-£304	-£270
Battery storage flexibility*	Three primary	-£0.8	-£1.2	-£1.0
	WPD	-£128	-£193	-£151
	GB	-£343	-£925	-£678

*These scenarios also include hot water flexibility in 100% of HP homes

Drawing together learnings across all work packages for the Peak Heat project brings out the following recommendations:

- Focus in the near term on incentivising those flexibility measures that have most impact and are lowest cost to WPD – incentivising hot water flexibility is key here. Engage with the heating engineer / installer / controls sector and support the development of a standard setting for heating controls to shift the timing of hot water generation.
- Value the temporary nature of heat flexibility – these solutions provide the opportunity for expenditure only when mitigation is needed and is incremental, unlike large capital expenditure on reinforcement.
- Explore the potential offered by tariff structures that charge residential customers according to their peak power demands to maximise reduction in peak.

- Explore new ways of incentivising diversity (such as these tariff structures) to mitigate additional pressures flexibility measures could cause.
- Explore how flexibility fiscal incentives for behind the meter battery storage and / or larger thermal stores (such as phase change material batteries) can be reduced as these measures are most effective at reducing peak loads.
- Investigate other ways of relieving more capacity in the networks – using ‘network side’ flexibility approaches alongside demand side flexibility approaches.

The analysis in Peak Heat shows that demand side flexibility measures can only partially mitigate the impact of additional electric heating load in 1-in-20 cold conditions, and significant network upgrades will likely be required. However, flexibility measures can defer substation upgrades and reduce overall costs for networks. Reinforcements required for EV charging were not considered in this analysis. If earlier network reinforcements are required to support EV charging at peak time, then it is likely that less heat flexibility would be required to reduce network constraints. However, if EV charging can be managed to occur outside peak periods, the results of this analysis would be largely unaffected. There will be a greater need for electricity distribution networks to cater for 1-in-20 winter conditions in future, and so a range of options (including both heat flexibility and reinforcement) should be explored to ensure customer’s heat demands can be reliably met under these conditions. Flexibility measures are likely to be more cost effective than network reinforcements, but networks will need to assess whether there is sufficient flexibility available based on the number of heat pump households willing to provide this demand side response in practice.

1. Work package scope, approach and outputs

This work package covers the high level cost benefit analysis of incentivising heat flexibility solutions under several scenarios within Peak Heat. It also brings together key findings from across all five work packages and makes recommendations for WPD.

1.1. Work package scope

This report details the methodology and outputs of the fifth (and last) work package of the WPD Peak Heat project, which builds on all previous work packages. In WP1, homes were categorised into eight house archetypes. WP2 provided an overview of the technologies and mechanisms that could be deployed by 2030 to deliver low carbon electric heating in the UK. In WP3, electrical demands were modelled for each house archetype with a heat pump installed under different weather conditions and with different flexibility measures applied. WP4 covered the modelling of heat flexibility solutions at the primary and distribution substation levels.

WP5 covered the high level cost benefit analysis (CBA) of implementing flexibility measures evaluated in previous work packages. This involved:

1. Conducting a high-level CBA to identify the potential lowest cost options / scenarios;
2. Comparing the long run marginal cost of upgrading the LV network versus the cost of incentivising the heat flexibility measures as modelled in WP3 and WP4 as a way to reduce peak demand (and therefore required cost to upgrade the LV network).

The purpose of the CBA is to assist WPD in assessing a range of potential heat flexibility interventions.

This work package also draws together all of the findings from the research to make recommendations for WPD. These can be used with the CBA outputs to inform WPD’s approach to heat electrification and flexibility.

1.2. Work package approach

The process followed in WP5 is outlined below. Full details of the methodology are provided in section 2.

1. The impact of increasing numbers of heat pumps (HPs) on the network at each distribution substation in the three study areas was estimated by; looking at the number and type of homes on each distribution substation, assigning heat pumps (HPs) to these homes to align with WPD DFES heat pump uptake, and using HP

After Diversity Maximum Demands (ADMDs) derived from the modelling done in WP3 and WP4 to calculate peak demand on an annual basis for each distribution substation. It should be noted network upgrades required to support electric vehicle (EV) charging were not considered in this analysis.

2. This annual peak load was compared to the nameplate rating of the distribution substation for each year to 2050 and upgrades were triggered when the peak load was 90% of the nameplate rating, i.e. when overloading was imminent. If, by implementing flexibility measures, the peak load was reduced to the extent that overload of the distribution substation was deferred in that year, then these flexibility measures were assumed to be incentivised and implemented. The minimum amount of flexibility required to keep the distribution substation from overloading was assumed to be incentivised.
3. The costs of upgrading the LV network and the costs of incentivising heat flexibility measures as modelled in WP3 and WP4 were compared across different scenarios in order to compare the relative benefits of potential heat flexibility interventions.

1.3. Work package outputs

The outputs of WP5 presented in this report are:

- A description of how the high level CBA was undertaken, and the results of the CBA for the three primaries study areas (sections 2 and 3).
- A simple extrapolation of the results to the WPD network and GB distribution network (section 3).
- Conclusions and proposed recommendations for WPD, presented in section 4.

2. CBA scope, methodology, and assumptions

The high level CBA identifies the potential lowest cost options to accommodate heating demand across flexibility scenarios. It analyses the impact of heating demand for all individual distribution substations in the Peak Heat study areas annually from 2021 to 2050, with an extrapolation to the WPD network and GB.

2.1. CBA scope

The aim of the Peak Heat CBA is to quantify the potential financial benefits of implementing heat flexibility solutions, the peak impact of which was modelled in previous work packages. WP4 modelled heat flexibility solutions at the distribution substation level, analysing the impact on peak load from different measures under various scenarios. This work package features a high level CBA, identifying the potential lowest cost options across these scenarios. This was assessed by comparing the costs of each of these measures and the benefits they afford WPD in terms of capacity release and deferral of the cost of traditional reinforcement.

This CBA focusses on the distribution substation level in alignment with the previous work packages technical analysis. Substation level results are also extrapolated to estimate costs and benefits at the WPD and GB scales for distribution substation level. The benefits have been quantified up to the year 2050.

It should be noted network upgrades required to support EV charging were not considered in this analysis. The impact of EV charging will depend on the level of EV uptake and how EV charging is managed. If earlier network reinforcements are required to support EV charging at peak time, then it is likely that less heat flexibility would be required to reduce network constraints. However, if EV charging can be managed to occur outside peak periods, the results of this analysis would be largely unaffected.

The scenarios from WP4 chosen for cost benefit analysis are those in which weather conditions are 1-in-20 cold conditions, and where heat pump uptake across substations is ‘high’, as it is under these assumptions where most distribution substations are overloaded, giving more opportunity to compare the costs of reinforcement due to overload vs the cost of modelled heat flexibility measures. The results from these scenarios (from WP4) for each substation archetype for 2030 are shown in the table below. Scenarios 4, 9, 10, 11 and 12 are those used in the cost benefit analysis.

These scenarios are:

- **Scenario 4 ('BAU')** – this is a 'worst case' scenario, in which heat pump (HP) uptake is high, 1-in-20 cold conditions are experienced, electricity price is fixed, and no heat flexibility measures are incentivised – this forms the "do minimum" or Business as Usual traditional reinforcement scenario, against which other scenarios are compared.
- **Scenario 9 ('Hot Water flexibility')** – this is a scenario in which electricity price is variable, all homes with heat pumps allow flexible hot water generation and this generation is programmed to occur at the lowest cost possible to meet hot water demands. This hot water flexibility is also included within all of the following scenarios:
- **Scenario 10 ('Temperature flexibility')** – in this scenario electricity price is variable, and all homes with heat pumps allow flexible hot water generation and more flexible indoor temperatures (a small change in temperature was allowed, with optional pre-heating up to 21°C in the afternoon and 21±1°C during occupied periods (versus a baseline with preheating up to 19°C in the afternoon and 21±0.5°C during occupied periods)). These flexible indoor temperatures are shown by the dashed lines in the figure below.

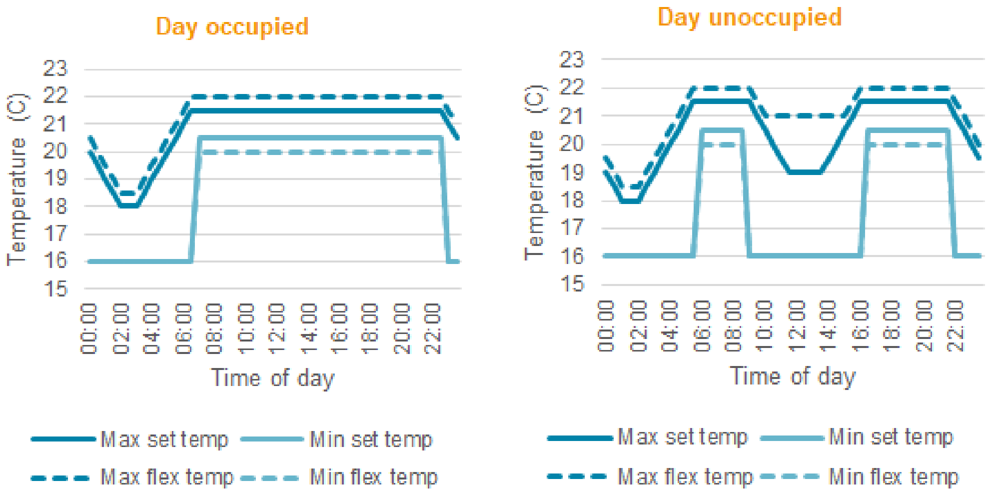

Figure 3. Range of flexible temperatures allowed in Scenario 10 (vs baseline set temperatures) throughout the day for occupied and unoccupied homes

- **Scenario 11 ('Buffer tank flexibility') –** in this scenario electricity price is variable, and all homes with heat pumps allow flexible hot water generation and also have buffer tanks that can store a relatively small amount of heated water before it enters the heat distribution system.
- **Scenario 12 ('Battery flexibility') –** in this scenario electricity price is variable, all homes with heat pumps allow flexible hot water generation and 50% of homes with HPs also have electric battery storage. Battery capacities, charge rates and efficiencies used for each archetype were determined in WP3 and are listed in the table below.

Table 2. Battery capacities, charge rates and efficiencies used in scenarios with batteries

Archetype code	Battery charge/discharge rate (kW)	Usable battery storage capacity (kWh)	Battery charge/discharge efficiency (%)
DH-G	7	13.5	90
DH-P	7	13.5	90
SH-G	5	10.0	90
SH-P	5	10.0	90
MT-G	3	5.0	90
MT-P	3	5.0	90
FI-G	3	5.0	90
FI-P	3	5.0	90

Programming hot water generation to occur at the lowest cost possible to meet hot water demands ('hot water flexibility') was applied in all non-baseline scenarios as it was assumed in WP4 that this measure would be relatively easy to implement in practice by programming when hot water cylinders can and cannot charge during the day.

Table 3 below has been taken from the WP4 assessment. It shows the peak load for each distribution substation archetype, and for each of the flexibility scenarios considered.

Table 3. Modelled scenario results for all distribution substation archetypes with high levels of heat pump uptake; maximum half hourly electricity demand (kW), time of maximum demand, date of maximum demand; colours indicate likely substation overload relative to typical continuous load nameplate rating – green: unlikely, yellow: possibly depending on rating, red: likely

	Maximum demand on substation and time and date of maximum demand							
Scenario	**Present day**	**2**	**4**	**9**	**10**	**11**	**12**	**Typical continuous load nameplate rating (kW)**
Weather		Average	Cold	Cold	Cold	Cold	Cold	
HP uptake		High	High	High	High	High	High	
Price		Fixed	Fixed	Variable	Variable	Variable	Variable	
Measures		None	None	Hot water	Hot water, Temp	Hot water, Buffer tanks	Hot water, Batteries	
D-70	206 kW 18:00 03/01	311 kW 17:30 13/01	340 kW 18:00 11/01	337 kW 18:00 12/01	336 kW 18:00 12/01	329 kW 18:00 12/01	312 kW 19:30 12/01	300 or 500
D-120	277 kW 18:00 03/01	450 kW 18:00 13/01	504 kW 18:00 12/01	497 kW 18:00 12/01	497 kW 18:00 12/01	486 kW 18:00 12/01	454 kW 19:30 12/01	500
D-200	397 kW 18:00 03/01	635 kW 18:00 12/01	702 kW 18:30 12/01	692 kW 18:00 12/01	689 kW 18:00 12/01	675 kW 18:00 12/01	648 kW 19:30 12/01	500
S-70	188 kW 18:00 03/01	234 kW 17:30 13/01	247 kW 18:00 13/01	244 kW 18:00 12/01	243 kW 18:00 12/01	241 kW 18:00 12/01	227 kW 19:30 12/01	315
S-120	249 kW 18:00 03/01	320 kW 18:00 13/01	346 kW 18:00 12/01	343 kW 18:00 12/01	343 kW 18:00 12/01	338 kW 18:00 12/01	309 kW 19:30 12/01	500
S-200	349 kW 18:00 03/01	491 kW 18:00 12/01	524 kW 18:00 12/01	518 kW 18:00 12/01	517 kW 18:00 12/01	506 kW 18:00 12/01	480 kW 19:30 12/01	500
S-350	539 kW 18:00 01/01	695 kW 18:00 13/01	751 kW 18:00 11/01	742 kW 18:00 12/01	741 kW 18:00 12/01	731 kW 18:00 12/01	700 kW 19:00 12/01	500 or 800
T-70	177 kW 18:00 03/01	206 kW 18:00 11/01	211 kW 18:00 11/01	210 kW 18:00 12/01	210 kW 18:00 13/01	208 kW 18:00 12/01	197 kW 19:00 12/01	315 or 500
T-120	234 kW 18:00 03/01	279 kW 18:00 12/01	294 kW 18:30 12/01	292 kW 18:00 12/01	293 kW 18:00 12/01	288 kW 18:00 12/01	280 kW 19:00 12/01	500 or 800
T-200	327 kW 18:00 03/01	376 kW 18:00 13/01	398 kW 18:00 13/01	395 kW 18:00 12/01	395 kW 18:00 12/01	391 kW 18:00 12/01	377 kW 19:00 12/01	500
T-350	493 kW 18:30 03/01	616 kW 18:00 12/01	644 kW 18:30 12/01	638 kW 18:00 12/01	636 kW 18:00 12/01	629 kW 18:00 12/01	601 kW 19:00 12/01	500 or 800
T-600	769 kW 18:30 03/01	970 kW 18:30 12/01	1,035kW 18:30 12/01	1,020kW 18:00 12/01	1,019kW 18:00 12/01	1,003kW 18:00 12/01	978 kW 19:00 12/01	500
F-70	167 kW 18:00 01/01	186 kW 18:00 13/01	189 kW 18:00 13/01	188 kW 18:00 11/01	188 kW 18:00 11/01	186 kW 18:00 12/01	178 kW 19:00 12/01	500
F-120	209 kW 18:00 03/01	239 kW 18:30 12/01	249 kW 18:00 12/01	247 kW 18:00 12/01	246 kW 18:00 12/01	244 kW 18:00 12/01	234 kW 19:00 12/01	500
F-200	282 kW 18:30 01/01	333 kW 18:30 12/01	348 kW 18:00 11/01	345 kW 18:00 12/01	345 kW 18:00 12/01	340 kW 18:00 12/01	326 kW 19:00 12/01	500
F-350	422 kW 18:30 03/01	508 kW 18:30 13/01	546 kW 18:30 12/01	539 kW 18:00 12/01	537 kW 18:00 12/01	530 kW 18:00 12/01	512 kW 19:00 12/01	500 or 750

This high level CBA compares the cost of upgrading the LV network (the baseline scenario) and the costs and financial benefits occurring over and above those in the baseline scenario from flexibility measures under each of the above scenarios. We have used the term “high level” to denote the fact that it is a simplified CBA which only explores direct costs and benefits.

The cost to the DNO under each of these scenarios, includes:

- The cost of reinforcing the network (upgrading the distribution substation) when a distribution substation becomes overloaded.
- The cost of incentivising heat flexibility measures (assuming that the technologies needed to provide this flexibility are already installed and that the cost of installing is borne by the customer – see assumptions in Appendix A)

The benefits to the DNO, under each of these scenarios, include:

- The benefit from the deferral of reinforcement of the network through the use of heat flexibility measures, resulting in a lower present value of the costs.
- Any mitigated reinforcement (i.e. deferral beyond 2050) represents additional savings.

This cost benefit analysis does not include:

- The wider benefits of incentivising flexibility measures (beyond the deferring or mitigation of traditional reinforcement), e.g. societal or carbon benefits.
- Changes in energy costs to consumers which may arise through a change in demand, or a change in pricing structure (e.g. use of Time of Use tariffs to incentivise load shifting).

2.2. Methodology

In WP1, three primary substation areas were selected based on geographical spread across the WPD network, high expected heat pump uptake and constrained HV/LV transformers. These are shown in Table 4.

Table 4. Selected study areas

Primary substation	Licence area	DFES non-hybrid HP uptake (2030)	Demand headroom (MVA)	Geography
Mackworth	East Midlands	3,135	3.32	Village / Rural
Newport East Primary	South Wales	3,443	7.1	City
Bath Road Primary	South West	2,659	0.6	Town

Data from WPD on each of the 234 individual distribution substations (including only those with >50 domestic customers connected, representing a total of 46,189 domestic customers) under each of the three primary substations was used to identify each distribution substation rating, number of domestic customers and the current maximum demand (MD) of that transformer[1] (further detail is provided in the WP4 report).

The number of properties connected to each distribution substation were classified into house archetypes as part of WP1 and WP3. These house archetypes are given in Table 5.

Analysis conducted within WP4 modelled each of the distribution substations under these primary substations through the creation of 16 distribution substation archetypes, based on the number of domestic customers and mix of property types on each distribution substation. Peak load impacts from heat pump uptake on these substation archetypes in 2030 were estimated by assigning heat pumps to properties to simulate overall uptake in line with the WPD Customer Transformation DFES scenarios.

WP5 builds on this by analysing impacts for all individual distribution substations in the Peak Heat study areas, annually from 2021 to 2050.

Table 5. Explanation of abbreviated archetype codes

House archetype code	Description
DH-G	Detached house, good wall insulation performance
DH-P	Detached house, poor wall insulation performance
SH-G	Semi-detached house, good wall insulation performance
SH-P	Semi-detached house, poor wall insulation performance
MT-G	Mid-terrace house, good wall insulation performance
MT-P	Mid-terrace house, poor wall insulation performance
Fl-G	Flat, good wall insulation performance
Fl-P	Flat, poor wall insulation performance

In WP4, a moderate heat pump uptake scenario of about 1,000 heat pumps were assumed to be installed on each primary substation – a level roughly in line with the level of uptake in 2025 in the DFES Leading the Way (LW) and Consumer Transformation (CT) scenarios. In the high uptake scenario this was increased to 2,500-3,500 per primary, in line with 2030 levels of uptake in these scenarios for each primary area.

A high level of HP uptake was adopted for the CBA, and so for 2030 the same levels of uptake were assumed for each primary as that assumed in the high uptake scenario in WP4 (2,500 – 3,500 per primary). Uptake levels were extended to 2040 and 2050 by taking CT scenario uptake numbers per primary for these years, and then extrapolated on a linear basis for all years in between. These HPs were assigned to house archetypes in order of suitability for heat pumps across the 234 distribution substations and then iteratively adjusted for each primary

[1] In a small number of cases this data was missing, and so we have estimated this based on a comparison of actual customer numbers and MDs for other substations

until the uptake levels for the three primary substations were approximately aligned with their respective predicted uptake numbers in the DFES. This is illustrated in Figure 4and described further in the WP4 report.

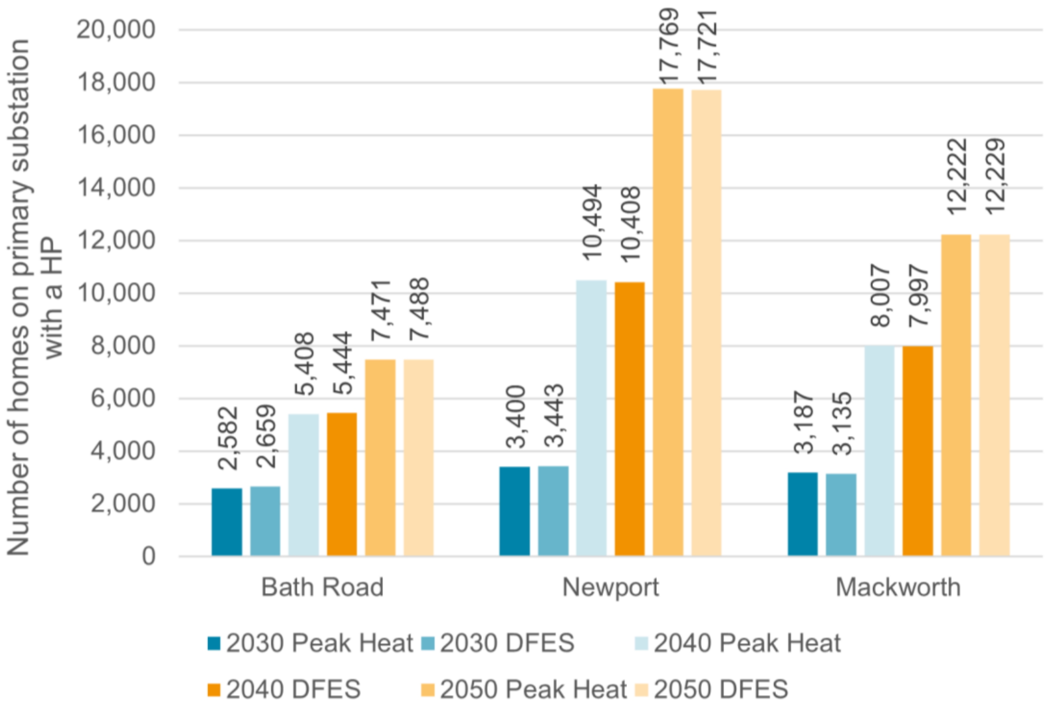

Figure 4. Number of homes on each primary substation with a heat pump installed under DFES and Peak Heat uptake scenarios

Suitability for heat pumps was judged based on (see WP4 report for more detail):

- **House type:** sufficient space is needed both outdoors and indoors for a heat pump, making detached and semi-detached houses the most likely to be suitable and flats the least likely to be suitable.
- **Thermal insulation:** properties with good levels of insulation are better suited to heat pumps as they are less likely to require significant energy efficiency improvements to be made before a heat pump can be installed.
- **Current heating type:** Gas boilers are the most common heating type in most house archetypes. Houses with non-fossil fuel boilers (most common in DH-G homes on Bath Road primary) are likely to be early heat pump adopters as they have more potential to save on fuel costs than gas-heated homes. Houses with electric storage heaters (common in flats on all three primaries) are harder to retrofit with hydronic heat pumps because a heat distribution system needs to be installed.

For each house type and modelled flexibility scenario, a HP After Diversity Maximum Demand (ADMD) was used. To derive the ADMDs, the individual house archetype load profiles determined in WP3 were applied to 50[2] properties of each house archetype. As in WP4, stochastic profiles based on the archetype average were used to generate unique thermal demand profiles for each individual house in order to simulate diversity across the 50 properties. The maximum total demand across these 50 modelled properties was then calculated and divided by 50 to determine the ADMD per property.

These HP ADMDs for each house type and modelled scenario were then summed across all HP properties to derive a total peak demand from heating for a particular distribution substation. This was then added to the existing maximum demand to give a total peak demand for that distribution substation. Historical half hourly aggregate demand data for the three primaries under study confirmed that maximum demands occur in the evening, and this was assumed to be true across all distribution substations.

The impact of flexibility measures on each distribution substation peak demand was calculated by applying a different HP ADMD to each house type. These represented average ADMDs for homes of different types with different insulation performances when flexibility measures are applied. These ADMDs are summarised for each scenario in Table 6.

Table 6. Heating ADMD (kW) by house type with and without different flexibility measures applied

	Heating ADMD by house type (kW)							
Scenario	**DH-G**	**DH-P**	**SH-G**	**SH-P**	**MT-G**	**MT-P**	**FI-G**	**FI-P**
ASHP (no flex)	4.28	7.12	3.21	4.59	1.92	2.64	1.19	1.57
HW flex	3.89	6.65	2.86	4.22	1.68	2.44	0.96	1.31
Temp flex*	3.78	6.42	2.79	4.04	1.66	2.35	0.94	1.23
Buffer flex*	3.81	6.37	2.77	3.99	1.67	2.34	0.95	1.24
Battery flex*	1.41	4.55	1.24	2.57	0.91	1.69	0.06	0.41

*These scenarios also include hot water flexibility in 100% of HP homes

The peak demand per distribution substation was calculated for key forecast years (2030, 2040 and 2050) and then interpolated for all years in between. This gave annual peak demand for each distribution substation to 2050, and enabled an annual comparison of this peak with the rating of the transformer. Traditional network reinforcement was then assumed to be deployed wherever the transformer load exceeded 90% of the nominal rating of the equipment. It assumes that:

- When distribution substations rated less than 1000kVA are overloaded they are replaced with a transformer large enough to meet forecast demand for 2050.

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[2] A value of 50 was chosen because it was found that ADMD values levelled off before 50 properties, meaning the ADMD values for e.g. 100 or 200 homes would have been similar.

- When distribution substations rated at or over 1000kVA are overloaded, an additional 800kVA transformer is added to the network as well as new feeders.

The capital cost of reinforcing these transformers (see Table 8) is then accounted for in the year in which reinforcement is triggered.

For each distribution substation, the overall peak may be lowered enough through the use of flexibility measures to defer the need for reinforcement (i.e. defer the exceedance of the nominal rating of the equipment) in any one year.

This capacity release and subsequent potential deferral of traditional reinforcement results in a lower present value of the cost of this reinforcement, due to the time value of money (see Appendix A for discounting assumptions). In this way, the benefit from flexibility measures was accounted for within each scenario.

The accounting for costs of implementing these flexibility measures assumed that any costs coincide with roll out of flexibility measures. Both of the following criteria had to be satisfied in order for roll out to take place:

- Flexibility measures would only be rolled out if their roll out reduced distribution substation peak demand to be below the nominal rating for that year.
- Distribution substation peak demand in the baseline scenario (i.e. with no flexibility measures applied) exceeded nominal rating for that year.

If flexibility measures were not sufficient to keep substations from being overloaded, then substations were upgraded rather than implementing flexibility measures. This process is represented in the figure below.

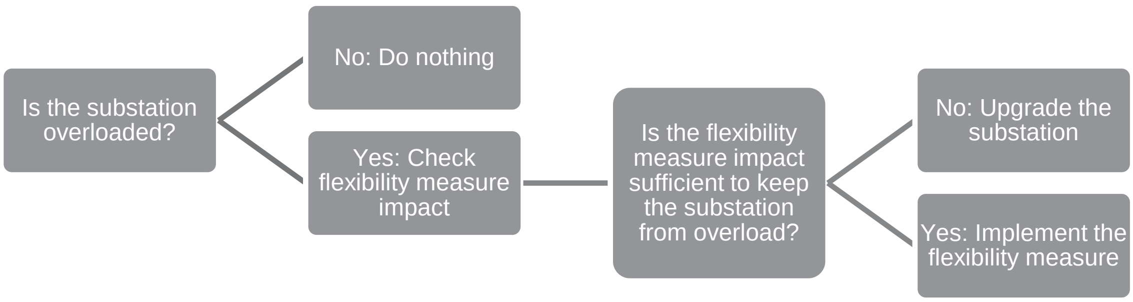

Figure 5. Decision process for implementing upgrades or flexibility measures per substation

Flexibility incentive costs are assumed to be paid only for the capacity required to keep a substation from becoming overloaded and no more (so minimising the number of customers needed to be incentivised by WPD to provide their flexibility).

Reinforcement and flexibility measure costs were summed across all substations in each year for all scenarios, and a discount rate (of 3.5%[3]) was applied to obtain the cumulative net present value (NPV) of each scenario for 2030, 2040 and 2050 for the three primary substations. These figures were compared for each scenario against the BAU traditional reinforcement case to

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[3] This is the discount rate recommended for <= 30 years in the Ofgem CBA template as per the HMRC Green Book.

ascertain the potential benefit achieved if these heat flexibility solutions were rolled out. The overall process followed is summarised in Figure 6 below:

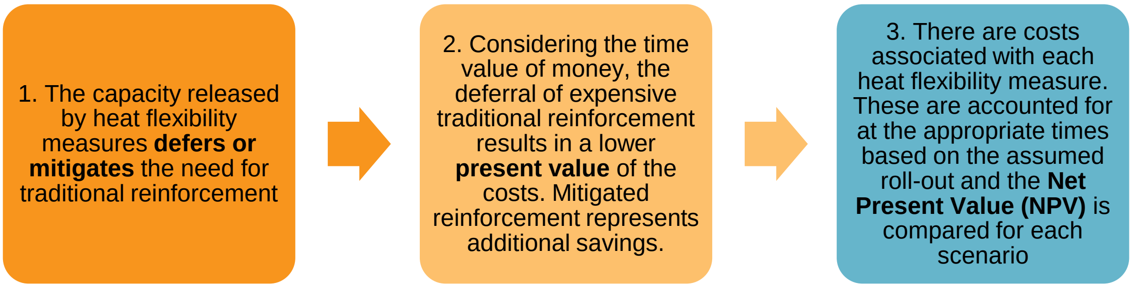

Figure 6. Overall process followed to determine NPV for flexibility scenarios

The methodology detailed so far applies to the three primaries under analysis within the Peak Heat project. To calculate costs and benefits of a wider WPD and GB-scale roll out of heat flexibility measures, scaling factors were used based on the uptake of domestic heat pumps at the WPD and GB level. Uptake at the WPD level was assumed to reflect the WPD DFES Consumer Transformation (non-hybrid) heat pump uptake scenario and uptake at the GB level was assumed to reflect the FES Consumer Transformation (non-hybrid) heat pump uptake scenario. Costs and benefits were assumed to scale in line with the uptakes forecasted in these scenarios. So for example in 2050, uptake in heat pumps at the WPD wide level is estimated in the CT scenario to be 156 times greater than uptake on the 3 primaries under study, so costs and benefits were multiplied by a factor of 156. The scaling factor from primaries to WPD wide level and from WPD to GB scale are detailed in the table below.

Table 7. Scaling factors used to calculate costs and benefits of WPD wide and GB-scale roll out of heat flexibility measures

Scale factor	2030	2040	2050
From 3 primaries to whole of WPD network	171	161	156
From WPD network to GB	2.67	4.78	4.48

2.3. Assumptions

2.3.1. Reinforcement cost assumptions

Assumptions for traditional reinforcement are:

- Upgrades occur when peak demands reach 90% of the distribution substation continuous nameplate rating. This conservative assumption was included as load was forecasted to continue to increase and also to avoid excessive instances where the connected load would be larger than the transformer continuous rating, which could result in increased degradation of the transformer. In reality transformers are likely to be upgraded when peak loads are higher than 100% of continuous nameplate rating conditions (typically around 115% to 130% of nameplate) depending on local load cycle, and therefore this assumption will yield higher numbers of upgrades than expected in reality. This assumption will have a tendency to overestimate the amount of capital that will be need to spent to prepare the network for heat pumps and to bring forwards the dates when it needs to be spent.

- Upgrade costs are assumed to occur just prior to the point at which a substation becomes overloaded and needs to be upgraded.
- Substations are upgraded to the size required to meet forecast demand in 2050. The substation size options used were as follows. Note that substations larger than 1,000 kVA might be considered in future. Changes in the reinforcement costs for substations larger than 1,000 kVA would affect both the baseline and the flexibility scenarios. The total costs of the scenarios would change, but the relative differences between the scenarios would remain similar, and so the conclusions of this analysis would still hold.

Substation rating (kVA) options
100
200
300
315
500
750
800
1000

- In a scenario tested where multiple upgrades were allowed in the 30 year modelled period, substations were upgraded to the next largest size each time loads reached 90% of the nameplate capacity.

Key cost assumptions[4] associated with reinforcement are outlined in the table below. All distribution substation upgrade costs include necessary changes from PMT to GMT, new site costs and civil engineering works. Costs are based on fitting transformers into existing sites, and an additional 11kV feeder cost was included in the scenario when an 800kVA transformer was installed adjacent to a 1000kVA transformer. A 250m LV feeder cable cost has been added to account for an additional outgoing feeder from the distribution substation, so that the increased peak load could be spread across the LV feeders. In reality, the LV feeder length required could be larger or smaller than 250m, but this assumption has been applied consistently across all substations as an average.

[4] Statement of methodology and charges for connection to Western Power Distribution (South West) plc's electricity distribution system, WPD, May 2021

Table 8. Reinforcement cost assumptions. A midpoint between the mix/max cost range is used in CBA model

Distribution substation upgrades	Additional reinforcements	Cost used in CBA model (£)
Upgrade existing 100/200kVA substation to 315kVA; including change from PMT to GMT, new site, and civil engineering works	Plus additional 1x250m LV feeder	£77,545
Upgrade existing 315kVA substation to 500kVA	Plus additional 1x250m LV feeder	£57,300
Upgrade existing 500kVA substation to 800kVA	Plus additional 1x250m LV feeder	£68,267
Upgrade existing 800kVA substation to 1000kVA	Plus additional 1x250m LV feeder	£75,579
Installation of additional 800kVA substation	Plus additional 5x100m LV feeders; plus additional 1x200m 11kV feeder	£160,278

2.3.2. Flexibility cost assumptions

Flexibility measure implementation costs only include the cost element that would likely be borne by WPD in facilitating these measures to present the cost benefit from a network perspective. This would likely be in the form of an incentive to customers to provide flexibility from already installed assets or assets which are installed for a different primary purpose (e.g. a battery storage system installed for maximising value from onsite PV generation). Costs associated with the installation of necessary hardware to provide flexibility (such as embedding controls in heat pumps or installing add-on modules to enable control) are also not included, as this also falls into the category of installed assets, and it is also assumed that from 2030 and beyond, the majority of heat pumps will be sold with this capability already embedded.

This focus on cost of facilitation (rather than on cost of hardware) is in keeping with the overall aims of the Peak Heat project, which is to assess the potential around inherent heat flexibility (already existing) within the LV network. Under each scenario, WPD would likely incentivise each flexibility measure in the following ways:

1. **Flexible hot water generation**

   It was estimated that hot water generation accounts for around 1%-6% of peak demand, depending on the existing loads on a substation and level of heat pump uptake[5]. To alter hot water generation so that it occurs outside of peak periods**,** a relatively simple change to how a customer's hot water generation is initially programmed would be required. This would likely occur at the time of initial install (with HP) and would be carried out by the installer. The cost to WPD therefore would likely be the cost of working with HP

[5] 1% would be expected for substations with a moderate level of heat pump uptake (5-15% of homes) and some peak demand coming from non-domestic users; 6% would be expected for a higher level of heat pump uptake (15-30% of homes) with little or no peak demand from non-domestic users.

manufacturers and/or installers to train / advise installers to program hot water generation to occur outside of peak periods.

To estimate this, a proxy value was required as there is no data available on the potential cost to a DNO of influencing the training of an installer / heating engineer (especially on a per customer basis). It was assumed instead that this reprogramming of hot water generation could be conducted by a heating engineer in ~1 hour or less at an average hourly rate for a heating engineer in Newport of £34[6].

2. Temperature flexibility

To obtain flexibility from customers having relaxed temperature requirements (by 1°C) at peak, WPD could provide a financial incentive to the customer. Customer research undertaken by Delta-EE and ongoing customer research as part of the Smart Heat[7] project has shown that a financial reward is by far the most popular incentive, with a reduction in electricity bill being the preferred mechanism for achieving this. Almost 80% of customers surveyed would be happy with at least a 10% reduction on their annual electricity bill (total) to provide a 1°C reduction response at peak times. 35% would be happy with at least a 5% reduction on their annual electricity bill (total) for the same level of response. This is essentially an availability payment (paying for customer acceptance that this action may happen) equivalent to a 10% or 5% reduction in their annual electricity bill. Since these amounts were derived from asking customers what they would be willing to accept in general for allowing a reduction in their heat during peak times on the network, it is reasonable to assume that this amount would likely be less if it was specified that this reduction would only be actioned for a very limited number of times during the winter period. For this reason, an amount equivalent to a 5% reduction on a customer's average annual (total) electricity bill was therefore assumed to be sufficient to gain the response required. An 'average' heat pump customer electricity bill figure of £1,345 is used. This is arrived at through:

- Assuming a 17.4p/kWh average electricity cost[8].
- Multiplying this by the average annual household (non-heating) electricity usage[9] to obtain the cost of this electricity.
- Assuming an average home requires around 12,000 kWh[10] of heat per year and has a heat pump with CoP of three (average taken from WP3 analysis of HP performance under cold winter conditions across the two-month period under study) would use 4,000 kWh of electricity annually. Using the assumed average electricity cost gives an average home's heat pump running costs.
- These are added to average non-heating electricity usage to obtain an average total household (with a heat pump) electricity bill.

Using this methodology, the annual average incentive cost per household works out to be £67 (see Appendix A for further details). This incentive cost is high relative to the DUoS charge. A method to incentivise this measure might be for networks and suppliers to work

[6] https://www.hamuch.com/rates/heating-engineer
[7] Customer research conducted by Impact Ltd for ENWL as part of the Smart Heat NIA – unpublished as of March 2, and Delta-EE own customer research
[8] BEIS Average unit costs and fixed costs for electricity for UK regions (QEP 2.2.4), accessed via: https://www.gov.uk/government/statistical-data-sets/annual-domestic-energy-price-statistics
[9] https://www.gov.uk/government/statistics/energy-consumption-in-the-uk
[10] https://www.viessmann.co.uk/heating-advice/Do-heat-pumps-use-a-lot-of-electricity

together to incentivise temperature flexibility via price signals (e.g. a dynamic network charge or time of use tariff with a strong signal for peak turn down) – these price signals would likely be interpreted by a home energy management system that optimises the heat pump operation within certain constraints (e.g. minimum and maximum temperatures). The different ways that end users could be incentivised for flexibility is an area for future consideration.

Germany is an example of a market where households with heat pumps have historically been offered electricity tariffs where the network charge is waived[11] in exchange for allowing the heat pump to potentially be interrupted (up to three times a day for two hours at a time). As heat pumps become more common, Germany is moving away from this availability payment approach and towards a more market-led approach where networks rely instead on dynamic tariffs to incentivise demand reduction/turn-up.

3. Electric battery storage flexibility

To obtain flexibility from existing electric battery storage installed in customers' homes, WPD would likely need to pay these customers to 'use' their battery capacity during peak periods (charge the battery outside of peak times and 'discharge' during peak times to ensure HP draw on the network is lowered during peak).

It is assumed that battery flexibility would be procured via DNO flexibility markets (likely from demand response aggregators) in addition to being incentivised through use of system charges that vary depending on the time of day.

An approximate value for the use of customer's battery capacity at peak times was obtained through the use of historic bid data from residential battery storage aggregators to provide DNOs battery capacity via the Piclo Flex platform[12]. An analysis was conducted of these bids using the bid price and capacity offered, and assumptions around the capacity of the batteries and discharge times – see Appendix A for full assumptions and a worked example. An assumed revenue share of 30% for the aggregator[13] was used to determine an average value of customer battery capacity per hour. The amount paid to these customers per year was estimated by using WP4 outputs to see how many hours substations on average were overloaded across the two cold month periods within the battery storage scenario, and multiplying the hourly price by the likely number of hourly overload periods in a year.

It is assumed that batteries export to the home in which they are installed rather than to the grid, so any costs associated with exporting to the grid have not been accounted for. For the battery sizes assumed, there is sufficient peak demand in the homes that it is not necessary for batteries to also export to the grid.

4. Buffer tank flexibility

To obtain flexibility from existing buffer tanks installed in customers' homes, WPD would likely need to pay these customers to 'use' their buffer tank capacity during peak periods

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[11] Section 14a of the Energy Industry Act (EnWG) allows German energy suppliers to offer customers a reduced electricity tariff for a heat pump. Network operators charge a reduced network fee, which is passed on to customers via energy retailers.
[12] Piclo Flex historic competition data, accessed via: https://docs.google.com/forms/d/e/1FAIpQLSc-lDxZicbDkZy8WAyjdiLwuvSDefnjrmfB5AjMLq2uVsE_OA/viewform
[13] Based on Delta-EE conversations with aggregators procuring residential battery capacity

(fill the buffer tank outside of peak times and 'discharge' during peak times to ensure HP draw on the network is lowered during peak).

It is assumed that buffer tank flexibility would be procured via flexibility markets.

An estimate for the value of customer buffer tank flexibility used a similar approach and data sources to that which was used to determine the value of battery storage flexibility. There is no existing data on the valuation of the flexibility provided by a buffer tank, and considering the buffer tank an alternative form of storage the bidding data for storage capacity can be used as a proxy. Assumptions have been adjusted (see Appendix A) to reflect the buffer tank's smaller capacity and discharge time, and then a similar approach to electric battery storage flexibility was taken to determine an average value of customer buffer tank capacity per hour and total value across the year.

2.3.3. Flexibility cost uptake

In each of the flexibility measure scenarios analysed, it was assumed that all households with a heat pump installed would provide flexibility when incentivised. Incentives were only offered in the years where the provision of flexibility would prevent substations being overloaded, and hence defer substation upgrades. Once a substation is upgraded, the additional capacity can meet increasing demand for many years before the substation becomes overloaded again, and flexibility is not required in this time. The assumptions for each of the flexibility scenarios were that:

- The incentive for temperature flexibility requirements was provided to 100% of customers with a heat pump (but only in the years that flexibility procurement would prevent substations from being overloaded and hence defer upgrades). 100% take up of these incentives are assumed and capacity is provided as modelled in WP3 and WP4.
- Incentives for using buffer tank capacity for flexibility was also provided to 100% of customers with a heat pump (but only in the years that flexibility procurement would prevent substations from being overloaded and hence defer upgrades) and 100% take up of these incentives are assumed.
- The incentive for promoting hot water flexibility is also provided to 100% of customers with a heat pump. However this is assumed to be a one-off incentive (cost to WPD) occurring at time of HP install (the payment required to give to installers to alter pre-programmed hot water generation schedules), and so once this has been paid for this measure will continue to have the same reduction on load during subsequent future overload events. 100% take up of this incentive is assumed when offered in the years that flexibility procurement would prevent substations from being overloaded and hence defer upgrades. In reality, this measure would likely be implemented when hot water or heating controls needed to be replaced (and the engineer would re-programme hot water generation schedules at the same time), for all customers needing controls replacement rather than just re-programming hot water generation schedules on smaller proportion of homes, as is assumed here. Because the time when hot water is generated has little to no impact on customers, it is assumed that customers would not override these settings. However, it could potentially be necessary to provide an ongoing incentive to ensure that hot water flexibility continues to be provided.

- In the scenario for battery flexibility, 50%[14] of HP properties are assumed to also have a battery and are incentivised for use of that battery storage capacity for flexibility at peak times. Again, it is assumed that 100% of customers with batteries take up this incentive in the years that flexibility procurement would prevent substations from being overloaded and hence defer upgrades, and provide capacity as modelled in WP3. Capacity is dependent on archetype, and is provided again in Table 9 below.

Table 9. Battery capacities, charge rates and efficiencies used in scenarios with batteries

Archetype code	Battery charge/discharge rate (kW)	Usable battery storage capacity (kWh)	Battery charge/discharge efficiency (%)
DH-G	7	13.5	90
DH-P	7	13.5	90
SH-G	5	10.0	90
SH-P	5	10.0	90
MT-G	3	5.0	90
MT-P	3	5.0	90
FI-G	3	5.0	90
FI-P	3	5.0	90

The uptake assumptions in these flexibility scenarios are intended to be illustrative rather than predictive. The purpose of the scenarios is to indicate the level of investment required to implement these incentives, and the maximum potential benefit each of these measures could provide. In reality, not all properties with heat pumps would provide these flexibility measures, and so the actual costs and benefits would be lower. The amount of flexibility provided in practice would depend on the level of incentive offered. A summary of the assumptions made regarding flexibility measures is provided in Table 10.

[14] In WP4, various levels of battery uptake among homes with heat pumps were tested when choosing scenarios. It was found that higher levels of uptake resulted in greater peak demand reductions, but only up to a point. The point at which additional batteries made little difference in peak demand reduction was at around 50% of homes with heat pumps.

Table 10. Flexibility measure cost - assumption of cost of measure to DSO (Costs of incentivising use of existing assets during peak times to receive response required / response gained in each scenario)

Flexibility measure	Cost / home / year (£)	Assumed uptake of HP homes	Effect of measure
Hot water generation occurring outside of peak periods	£34 (one-off cost)	100%	Customer does not notice a change; hot water demand continues to be met but is generated outside of peak hours
Relaxed temperature requirements (by 1C) during peak*	£67	100%	Customer is made available to potentially having their heating reduced by 1C during peak cold winter events
Use buffer tank during peak*	£14	100%	The buffer tank is used to provide stored heated water at peak times to reduce heat pump draw at these times
Use battery during peak*	£191	50%	Battery capacity is used to provide stored electricity at peak times to reduce heat pump use of network electricity at these times.

*These scenarios also include hot water flexibility in 100% of HP homes

See Appendix A for full table of assumptions.

3.CBA results

There is a net cost benefit to incentivising all Peak Heat flexibility solutions over BAU to 2050. Battery flexibility offers the greatest potential savings of the different heat flexibility measures assessed.

3.1. Quantified cost benefit analysis results across scenarios

Figure 7 shows the net present value (NPV) cost of the baseline traditional reinforcement scenario versus the alternative scenarios with flexibility measures applied for the three primary substations under study. The chart on the left shows the case where multiple substation upgrades are allowed over the 30 year period, and the chart on the right shows the case where pre-emptive reinforcements are made to avoid making multiple upgrades over the 30 year period. In reality, the pre-emptive upgrade scenario is more likely, so only this scenario is considered in further analysis.

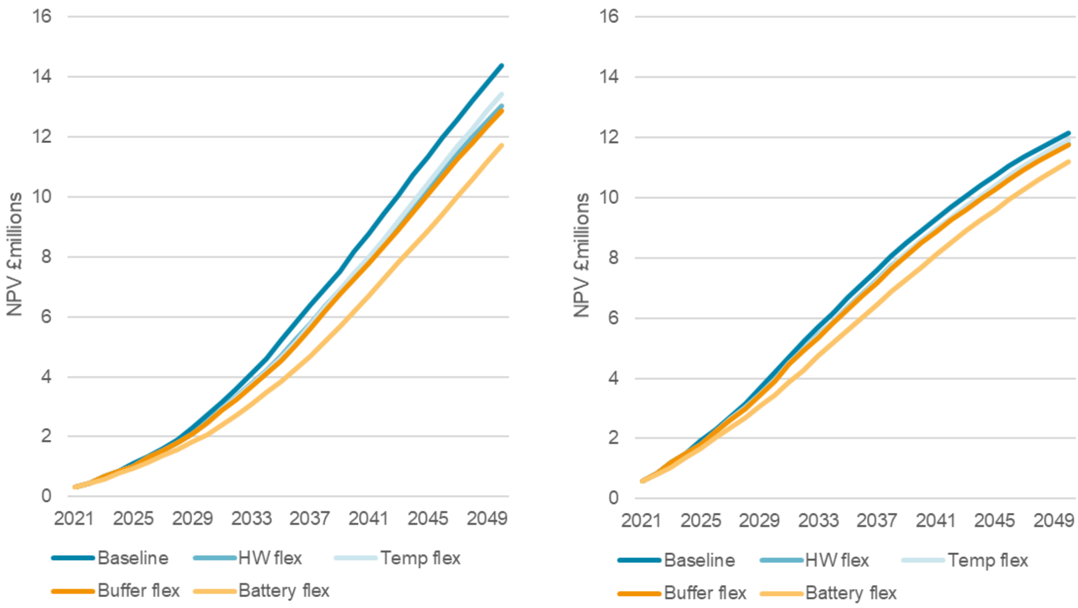

Figure 7. NPV (£millions) for each scenario at the 3 primary substations level, allowing for multiple distribution upgrades (left) and assuming pre-emptive reinforcement to have only single distribution upgrades (right) between 2020-2050

Comparing the two baseline scenarios, it can be seen that the multiple upgrade case has a lower NPV until 2043, but that the pre-emptive reinforcement case is more cost effective in the longer term (16% lower NPV in 2050).

The flexibility measure scenarios are more cost effective than the traditional reinforcement case throughout the 30 year modelled period, with battery flexibility giving the greatest overall cost reductions (8% lower NPV than the baseline in 2050 in the single upgrade scenario).

Table 11 shows the cumulative number of distribution substation upgrades required for the 234 substations under study. In total, 187 of these substations will likely need to be upgraded by 2050 to meet additional demand from heat electrification, assuming high levels of heat pump uptake. Generally flexibility measures can delay upgrades by a few years at most, but all 187 upgrades are still necessary by 2050. The one exception is the battery flexibility scenario, where widespread use of electrical storage enables 17 distribution substations to avoid requiring upgrade before 2050. As a reminder, all scenarios consider the maximum level of flexibility uptake, so the benefits would likely be less in reality, particularly the battery uptake scenario which the DFES forecasts be significantly less than the 50% scenario investigated in this study (see the work package 4 report for further information).

Table 11. Cumulative number of distribution substation upgrades for the 234 substations under study across the three primary substations

Scenario	2030	2040	2050
Baseline	102	168	187
Hot water flexibility	93	164	187
Temperature flexibility	90	163	187
Buffer flexibility	89	163	187
Battery flexibility	70	135	170

Figure 8 shows how the NPV costs in 2030, 2040 and 2050 are split between network reinforcement costs and flexibility incentive costs. In the scenarios with hot water flexibility, temperature flexibility and buffer tank flexibility, the costs of flexibility incentives are relatively low, though the savings from deferring upgrades are relatively small. This is because these measures are fairly inexpensive, but can only provide a relatively small reduction in peak demand. The temperature flexibility scenario (which includes hot water flexibility) is the least cost effective option, as the demand reduction impacts are minimal relative to the incentive level required for households to allow small changes to their temperature set points.

In the battery flexibility scenario where 50% of homes with heat pumps also have batteries, reinforcement costs are about 20% lower due to the longer deferral of upgrades. Though the additional flexibility from batteries does come at a higher cost, this works out to be the lowest cost option overall throughout the 30 year period. In reality, the benefits of battery uptake would be less as battery uptake is likely to be lower than in this scenario according to DFES forecasts (see work package 4 report for further information), unless strong incentives are offered to encourage household investment in battery storage.

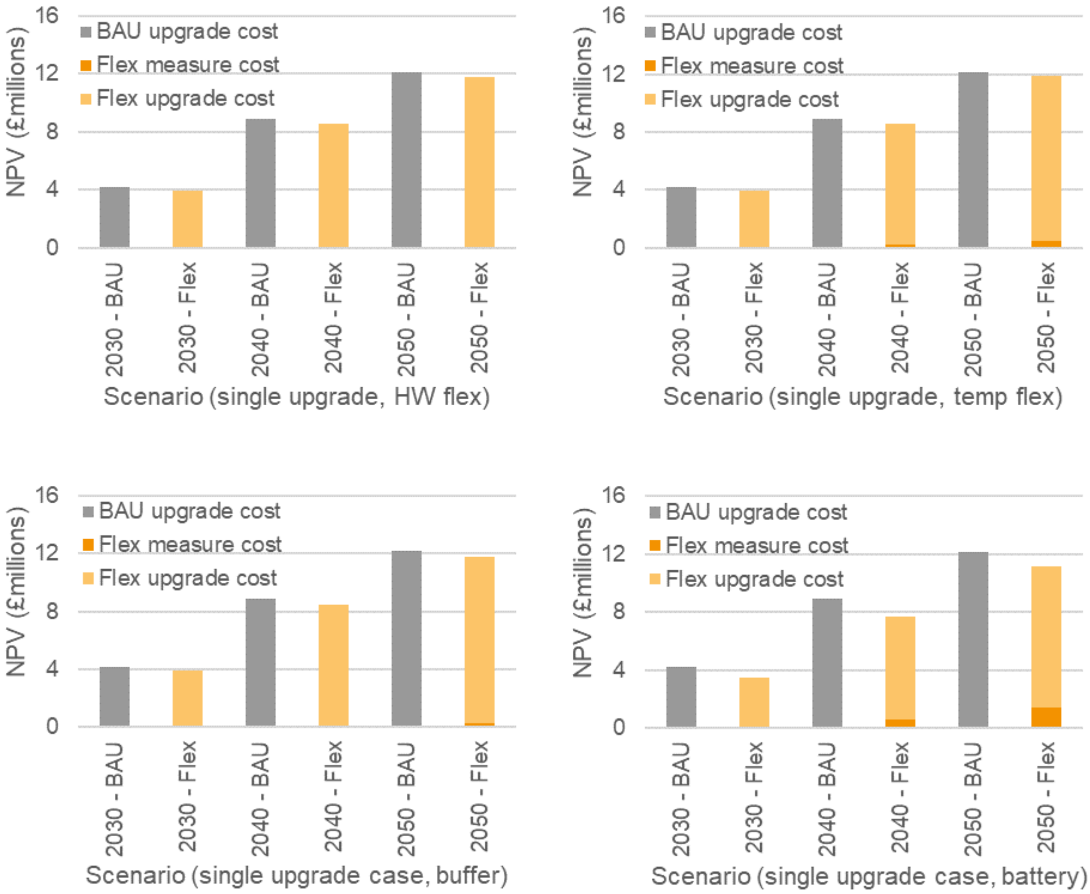

Figure 8. Breakdown of NPV costs (£millions) for network reinforcements and flexibility measures, at the 3 primary substation level, baseline scenario versus scenario with maximum flexibility measures, in multiple upgrade case (left) and single upgrade case (right)

Table 12 shows the net cost savings of the different flexibility scenarios relative to the baseline scenarios for the three primaries under study, the full WPD network, and the whole of GB. These results indicate that widespread use of demand side flexibility measures could potentially save WPD hundreds of millions of pounds in reinforcement costs by 2050. However, uptake of flexibility measures will be lower in reality than the illustrative 100% uptake levels used in these scenarios (or 50% in the case of electrical batteries), so savings would be lower in practice – likely in the order of tens of millions of pounds, though the exact figure will ultimately depend on how strongly households are incentivised to provide demand response.

Note also that in all scenarios, flexibility measures would need to be carefully implemented to ensure the new loads are diversified and not all shifted in the same way to form a new peak. This can be avoided with appropriate variable tariff structures, and/or programming in a randomised delay in response to price/weather signals.

Table 12. Cumulative net present value (£m) of Peak Heat flexibility measures compared to traditional reinforcement case at the three primary scale, WPD and GB-scale (rounded) – negative values indicate a net benefit of using flexibility measures compared to traditional reinforcement

Scenario	Scale	2030	2040	2050
Hot water flexibility	Three primary	-£0.2	-£0.3	-£0.4
	WPD	-£36	-£54	-£55
	GB	-£96	-£260	-£248
Temperature flexibility*	Three primary	-£0.3	-£0.3	-£0.2
	WPD	-£43	-£51	-£36
	GB	-£115	-£242	-£160
Buffer tank flexibility*	Three primary	-£0.3	-£0.4	-£0.4
	WPD	-£46	-£64	-£60
	GB	-£123	-£304	-£270
Battery storage flexibility*	Three primary	-£0.8	-£1.2	-£1.0
	WPD	-£128	-£193	-£151
	GB	-£343	-£925	-£678

*These scenarios also include hot water flexibility in 100% of HP homes

3.2. Results discussion

3.2.1. Sensitivity to flexibility incentive cost assumptions

As discussed in Section 2.3.2, there is a high degree of uncertainty around what it will cost to incentivise demand response actions from households with heat pumps. The level of incentive offered will impact the level of customer uptake – a factor not considered in the illustrative scenarios explored here, which assume 100% uptake of each measure. The value of incentives will also likely change over time as more households are able to provide flexibility and the supply therefore increases – when more flexibility is available, the level of incentive that can be provided to each household reduces. Figure 9 below shows the results of a sensitivity analysis on the costs of incentivising the different flexibility measures. The multiple substation upgrade case was used for the analysis. The analysis looked at:

- The central scenario, with assumptions as per Section 2 and Appendix A (shown in orange);
- A “free flexibility” scenario, where the flexibility comes at no cost to WPD (shown in light blue);
- A 50% cheaper scenario, where incentive costs are reduced by half (shown in mid blue); and
- A 100% more expensive scenario, where incentive costs are doubled (shown in dark blue).

In the scenarios with temperature, buffer tank and battery flexibility, it is assumed that hot water flexibility is utilised as well, but that this comes at no additional cost to access.

From Figure 9 it can be seen that the scenarios with hot water, temperature and buffer tank flexibility are not particularly sensitive to the levels of incentives assumed. This is because the vast majority of the costs in these scenarios are for network upgrades. Even if these measures came at no cost to WPD, the most they would save by 2050 relative to the baseline scenario is about 3-4%. The temperature flexibility chart shows that it is possible for these lower-impact measures to cost more than they save on network reinforcement costs – in this case with 100% uptake, the threshold is at around £135/year per heat pump household.

In contrast, the battery flexibility scenario is somewhat more sensitive to assumed incentive costs, as this measure could enable more significant reductions in network reinforcement costs. In the extreme case where all households with HPs have batteries and there is no incentive cost to WPD, savings by 2050 could be around 12% relative to the baseline traditional reinforcement scenario. On the other hand, even at a cost of close to £400/year per household with a battery, this would still give overall savings of about 4%. It is likely that this scenario also delivers many other benefits (such as mitigating carbon emissions and inconvenience to wider society associated with substation upgrades). Accounting for these additional benefits in a more detailed CBA would improve the cost effectiveness of batteries.

As domestic batteries show the greatest potential for overall cost reductions, it is recommended that further research focuses on how sensitive battery uptake could be in future to the level of incentive offered, and the implications this would have on the amount of flexibility available at different costs.

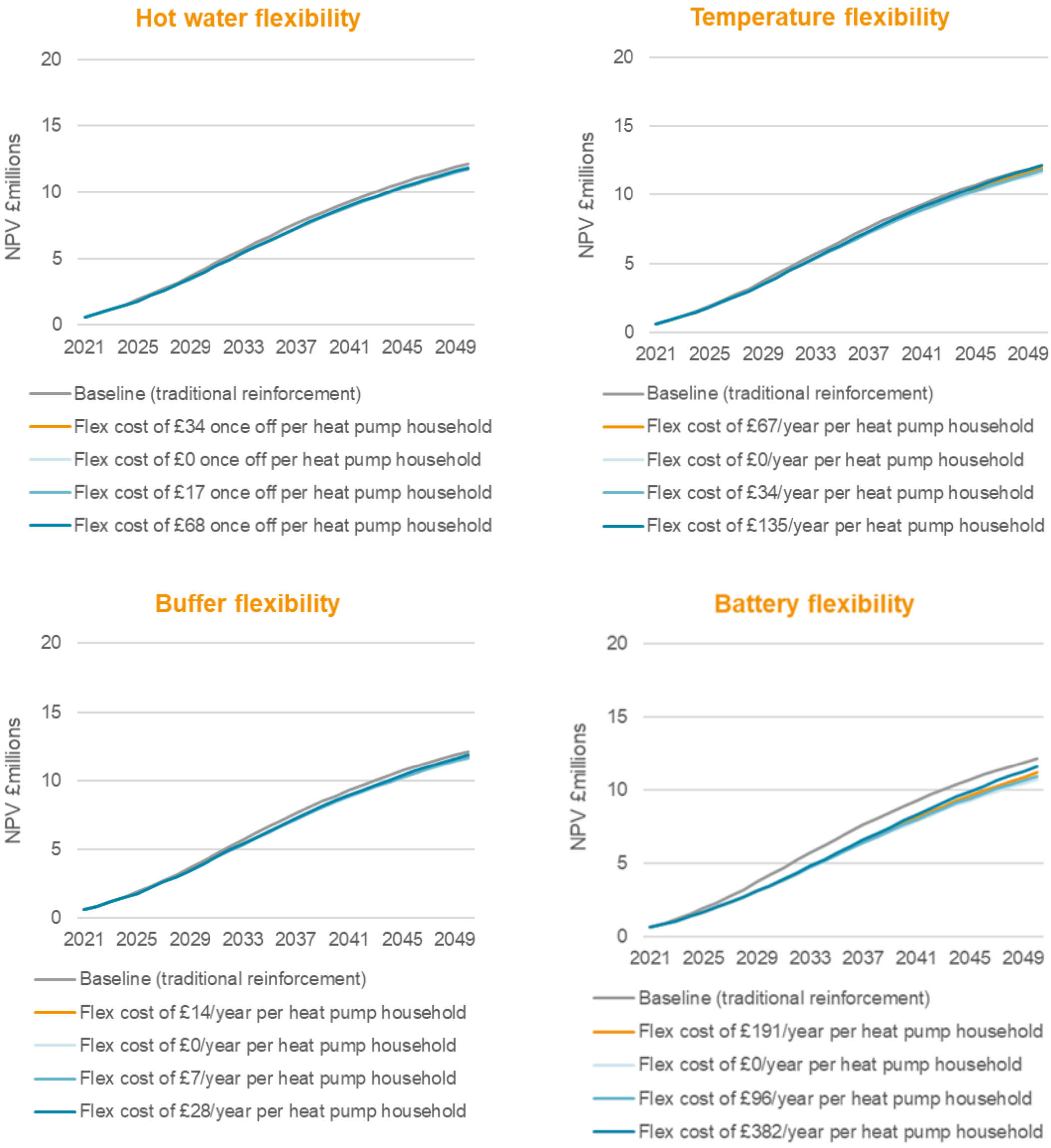

Figure 9. Sensitivity of NPV costs (£millions) to assumed incentive costs for different flexibility measures in the case where pre-emptive distribution substation upgrades are made to avoid having multiple upgrades in the 30 year modelled period

3.2.2. Longevity of solutions before upgrades

Some flexibility measures have more longevity than others – reducing peak demand enough so that reinforcement is deferred for a longer period. Programming hot water generation for load shifting on its own has the least longevity of each of the solutions analysed, delaying distribution substation upgrades by up to 1.4 years on average (see Table 13).

When temperature flexibility is added to this, the average length of delay increases to up to 1.7 years. Utilising buffer tank flexibility with flexible hot water generation has a similar outcome (1.9 years average delay).

For battery storage, particularly post-2030, the number of instances where this flexibility solution is implemented in consecutive years to defer reinforcement increases substantially, to an average of up to 4.5 years. Again, this would likely be lower in reality if fewer homes install batteries as forecasted in the DFES.

Table 13. Length of benefit given by different flexibility measures assuming maximum levels of household uptake

Scenario	Average length of time distribution substation upgrade can be delayed (years) if all HP homes provide flexibility (or 50% of homes in the case of battery storage)
Hot water flexibility	1.4
Temperature flexibility*	1.7
Buffer tank flexibility*	1.9
Battery storage flexibility*	4.5

*These scenarios also include hot water flexibility in 100% of HP homes

3.2.3. Limitations - cost assumptions

In this analysis, 100% uptake of flexibility measures (or 50% in the case of electrical batteries) is assumed among households with heat pumps, in line with heat pump uptake growth. Incentive costs here have been assumed based on what might be reasonable compensation to individual customers (or payments to heating engineers in the case of flexible hot water generation). It is also assumed that all customers have the same level of willingness to accept each measure (i.e. all are willing to provide the required flexibility response for the same price).

It would be reasonable to assume however that if a large response was required, WPD may need to pay higher incentives to capture those responses from customers less willing to accept the provision of flexibility, and so it is likely that whilst the costs used in the CBA for each measure provide a good approximation of the costs required, implementing flexibility measures may work out more costly for WPD when a larger response is required, to ensure enough customers participate in providing the required flexibility response. Further analysis could explore the price elasticity of flexibility supply to determine the point beyond which it becomes too expensive to incentivise more households to provide demand response compared to the cost of network reinforcement.

In this analysis we have had to make assumptions or use proxy values to estimate what the cost to WPD might be for incentivising these flexibility measures, as their implementation does not yet exist. In practice, there may be a range of different levels of payment for different types of flexibility, based on factors such as a customer's circumstances and preferences. The use of a single value for each type of flexibility is therefore a somewhat crude approximation, and further work could look to understand how this value changes for different customers and contexts. We have used relatively conservative incentive cost assumptions, so the savings calculations are more likely to be pessimistic. However, as noted in section 3.2.1, the relatively small flexibility available are a greater limiting factor in how much cost savings can be achieved. Other limitations

As previously mentioned, this is a high level or simplified CBA which compares costs across BAU and flexibility scenarios. As such this analysis does not capture:

- The wider benefits of incentivising flexibility measures (beyond the deferring or mitigation of traditional reinforcement), e.g. societal or carbon benefits.
- Changes in energy costs to consumers which may arise through a change in demand, or a change in pricing structure (e.g. use of Time of Use tariffs to incentivise load shifting).

Other limitations include:

- The analysis centres around distribution substations under the three primaries of focus for the Peak Heat project. To extrapolate results to WPD network and GB-scales, simple scale up factors have been used (see Table 7). Further work could be conducted to provide a more granular understanding of impact at the WPD network level by undertaking a distribution substation level analysis (similar to that conducted for each of the three primaries here) for the whole of the network.
- The analysis assumes the maximum level of flexibility measure uptake. The scenarios should therefore be treated as illustrative rather than predictive. The results show the maximum potential benefits from each type of flexibility measure. In reality, less flexibility is likely to be available, and substation reinforcements will be required earlier.
- Network upgrades required to support EV charging were not considered in this analysis. The impact of EV charging will depend on the level of EV uptake and how EV charging is managed. If earlier network reinforcements are required to support EV charging, less heat flexibility would be required to reduce network constraints. If EV charging can be managed to occur outside peak periods, the results of this analysis would be largely unaffected.

3.3. Impact of flexibility measures on primary substation upgrade costs

The costs of primary substation upgrades are not included in the cost benefit analysis calculations. Table 14 shows in what year the three primary substations under study would have peak demands exceeding their nameplate rating. It is likely that the primary substations would need to be upgraded at around this point. The Mackworth primary substation currently has peak demands above its nameplate rating and will likely need to be upgraded soon, regardless of what flexibility measures are applied in future. From the results for the Bath Road and Newport primaries, it can be seen that flexible hot water generation will not be sufficient to delay primary substation upgrades relative to the baseline BAU scenario with no flexibility. Temperature and buffer tank flexibility could delay primary substation upgrades by a year, though this would require all homes with heat pumps to provide this flexibility. Battery storage flexibility could delay upgrades by around 2 years, though again this is based on the assumption of widespread uptake among households with heat pumps.

Table 14. Current nameplate ratings and peak demands of three primary substations under study, and year that upgrade would be required under baseline traditional reinforcement and flexibility measure scenarios

	Bath Road	Mackworth	Newport
Nameplate rating (MW)	30.5	18.4	40
Current peak demand (MW)	25.5	19.1	32.1

Scenario	Year peak demand would exceed continuous nameplate rating		
Baseline	2027	2022	2029
Hot water flexibility	2027	2022	2029
Temperature flexibility	2028	2022	2030
Buffer tank flexibility	2028	2022	2030
Battery storage flexibility	2029	2022	2031

Table 15 looks at the cost savings (in NPV terms) from deferring primary substation upgrades by a number of years. Assuming a primary substation cost of around £4.23m (including equipment, cabling, site purchase) and a discount rate of 3.5%, a 2 year deferral can save over a quarter of a million pounds in NPV terms per primary substation. Accounting for these significant additional cost savings would further improve the potential cost benefits of flexibility measures.

Table 15. Cost savings from deferring a single primary substation upgrade

Number of years upgrade is deferred	NPV cost of primary substation (£millions)	NPV cost saving due to deferral (£thousands)	NPV cost saving due to deferral (%)
0	£4.23	£0	0%
1	£4.09	£143	3%
2	£3.95	£281	7%
3	£3.82	£415	10%
4	£3.69	£544	13%
5	£3.56	£669	16%
6	£3.44	£790	19%
7	£3.33	£906	21%
8	£3.22	£1,019	24%
9	£3.11	£1,127	27%
10	£3.00	£1,232	29%

4. Conclusions and recommendations

This section draws together learnings from all work packages and makes key recommendations for WPD. These include focusing in the near term on incentivising those flexibility measures that have most impact and are lowest cost to WPD and avoiding those measures that are unlikely to be effective for reducing peak loads.

4.1. Conclusions - Heat electrification and flexibility measures at the property level

WP3 demonstrates that peak loads on electricity distribution networks will be significantly higher if a large proportion of homes switch from gas/oil/LPG heating to electrically-driven heat pumps. Total electricity demand peaks will be around 4 to 6 times higher than peak non-thermal demands, depending on the house archetype. For most house archetypes the average demand profile peaked between 19:00 and 20:00 in the evening. Morning peaks are also relatively high between 4:00 and 9:00, with space heating loads coming on between 4:00 and 7:00 on average and non-thermal loads then picking up between 7:00 and 9:00. Total electricity demand was shown to be higher in larger homes and homes with less insulation.

WP3 also found that under cold conditions, many flexibility measures had a minimal impact on peak demands, and often resulted in peak-shifting rather than peak reduction at the individual house level:

- Switching to a variable tariff and allowing more flexible space heating and hot water generation had a negligible impact on peak demand compared to the baseline. Under these scenarios, heat demands are generally lower during periods when the electricity price is high. However, the absolute level of the daily peak demand remained the same, but was shifted to a different time period outside of these hours.
- The addition of a buffer tank also has little impact on peak demands. In fact, peak demands are slightly higher as a result of heat being generated and stored in the buffer tank ahead of high price periods.
- The addition of an electrical battery shifts a large amount of demand into a small timeframe and has the result of increasing peak demands by 50-80% depending on the house archetype, albeit at a different time from the current system peak demand period. In this scenario, peaks occur during the early morning hours when low electricity prices lead to the electrical battery charging at the same time as the hot water cylinder or buffer tank are being charged.

The introduction of electricity capacity supply limits in WP3 to test how much peak demand could be reduced rather than shifted with flexibility measures demonstrated that flexible heat and hot water generation enabled reductions of household peak demand of around 20-30%.

Better insulated properties enable more flexibility as they lose heat at a slower rate and can be pre-heated further ahead of demand. Properties with larger hot water cylinders also offer relatively more flexibility – especially in smaller properties where hot water generation represents a higher share of total heating demand.

Buffer tanks appear to only enable significant reductions (10-20%) in peak demand in properties with good insulation, since heat released from the buffer tank to the building is then lost at a slower rate compared to homes with poor insulation. Greater peak demand reductions could be achieved by having larger buffer tanks, or more compact thermal storage devices. It would be worthwhile therefore exploring in future work the impact (and relative cost benefit) of more innovative thermal storage solutions such as phase change heat batteries.

Electrical batteries can enable an additional 10-20% reduction in peak demand at most, depending on the size of the battery relative to total electrical demands. At lower levels of electrical battery uptake in line with the DFES, the impact would be almost negligible – this is because capacity levels assumed in the DFES are equivalent to only a small percentage (<5%) of homes having electrical batteries.

The impact of these measures on peak is summarised in the table below, which gives average HP ADMDs by house type. To derive the ADMDs, the individual house archetype load profiles determined in WP3 were applied to 50 properties of each house archetype. As in WP4, stochastic profiles based on the archetype average were used to generate unique thermal demand profiles for each individual house in order to simulate diversity across the 50 properties. The maximum total demand across these 50 modelled properties was then calculated and divided by 50 to determine the ADMD per property.

Table 16. Heating ADMD (kW) by house type with and without different flexibility measures applied

	Heating ADMD by house type (kW)							
Scenario	**DH-G**	**DH-P**	**SH-G**	**SH-P**	**MT-G**	**MT-P**	**FI-G**	**FI-P**
ASHP (no flex)	4.28	7.12	3.21	4.59	1.92	2.64	1.19	1.57
HW flex	3.89	6.65	2.86	4.22	1.68	2.44	0.96	1.31
Temp flex*	3.78	6.42	2.79	4.04	1.66	2.35	0.94	1.23
Buffer flex*	3.81	6.37	2.77	3.99	1.67	2.34	0.95	1.24
Battery flex*	1.41	4.55	1.24	2.57	0.91	1.69	0.06	0.41

*These scenarios also include hot water flexibility in 100% of HP homes

4.2. Conclusions - Heat electrification and flexibility at the network level

WP4 and WP5 showed that at the network level, a significant number of substations are likely to be overloaded during peak winter conditions under high levels of high heat pump uptake. Across the three primary substation areas under study, with no flexibility measures implemented, around 72% of distribution substations are upgraded by 2040, with this number increasing to ~80% by 2050. This is based on the conservative assumption that substations are upgraded when they reach 90% of their continuous rated capacity. In practice some of these could potentially be delayed by a few years as cyclic enhancements could allow 10-25% more headroom than assumed in this analysis.

Network level modelling of flexibility measures showed that many flexibility measures have a negligible or very low impact on peak demand during peak cold winter conditions. Allowing flexible hot water generation for example allows ~1% of demand to be shifted out of peak periods and the use of buffer tanks only reduced peaks by 1–2%. Implementing these measures had the effect of reducing the number of required distribution substation upgrades by ~10–15% in 2040 and 2050. Incentivising flexible hot water generation was found to be a cost-effective flexibility measure as long as incentive costs do not rise significantly above what is assumed in WP5. Buffer tank flexibility was also found to be cost effective at current assumed price points, although as previously discussed, the additional flexibility derived from buffer tanks is low. This is due to the fact that buffer tanks just help prevent heat pumps from short cycling rather than providing sufficient heat storage capacity to shift significant heating load out of peak periods.

Indoor temperature flexibility has a negligible impact (<1%) on peak demand and limited effectiveness for reducing peak loads. In terms of reducing the number of required upgrades, implementing this measure has a similar effect to the use of buffer tanks. However, because higher incentive costs are required to compensate for any potential inconvenience, temperature flexibility is less cost effective than use of buffer tanks.

Making use of flexible capacity within pre-existing electrical batteries in all homes with heat pumps had the greatest reduction of peak demands – by up to 9% at the distribution substation level, depending on the substation. As analysis in WP4 and WP5 showed, this level of reduction in peak could prevent a significant number of distribution substations needing to be upgraded. For the incentive costs assumed, use of battery storage proves more cost effective than network reinforcements. It should also be noted that this cost comparison does not include other costs associated with significant levels of substation upgrades, such as carbon emissions, which would further improve the business case for flexibility measures.

There is a big difference in peak heating demands in average winter conditions versus peak winter conditions. Figure 10 below shows the maximum half-hourly heat demand each modelled day for an S-200[15] archetype distribution substation versus the average daily temperature. In 1-in-20 winter conditions (about -4C average), the peak daily demand is around two times higher than in average winter conditions (about 4C average). Flexibility measures are therefore about twice as effective at reducing peak demands on an average day versus the coldest day – for example, adding electrical batteries in 50% of homes on this substation reduces the overall peak demand by about 8% on the coldest day compared to ~17% on an average winter day.

[15] An S-200 archetype is a distribution substation with mainly semi-detached homes and mix of other types of homes – see WP4 report for full substation archetype descriptions

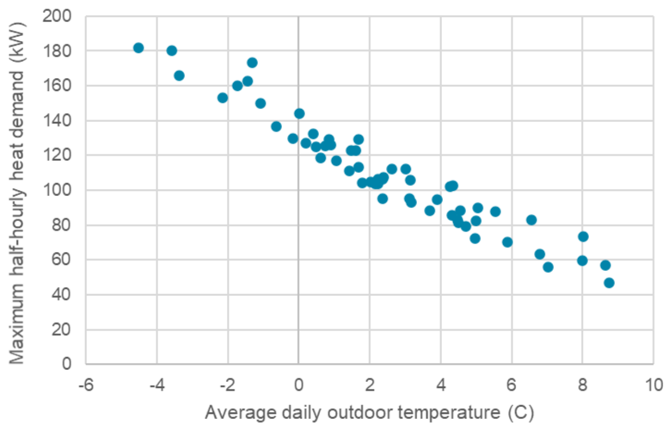

Figure 10. Maximum half-hourly heat demand per day versus average daily temperature for S-200 substation archetype with high level of heat pump uptake

4.3. Recommendations

How should network companies approach the challenges highlighted by Peak Heat? The analysis presented in this report and the previous Peak Heat reports enables a range of recommendations to be formulated.

A range of heat flexibility measures are available to WPD which may provide a cost benefit. WPD should explore these measures in more detail so that it can identify the most appropriate solutions:

- **Focus in the near term on incentivising those flexibility measures that have most impact and are lowest cost to WPD.** This includes increasing generation of hot water outside of peak periods (but also incentivising diversity in off-peak periods) and incentivising use of buffer tanks and electrical batteries.
- **Look for ways to reduce the costs of those measures that are unlikely to be as cost effective**. Incentivising indoor temperature flexibility as a measure should be lower priority as this is unlikely to be as effective for reducing peak loads and has a relatively high incentivisation cost relative to the benefits achieved, alongside potential impacts on customer comfort. Battery storage flexibility is highly effective at reducing peak and is likely to be cost effective, though further analysis is necessary into how levels of incentives offered would impact levels of uptake. One option for temperature flexibility is to achieve the same level of controllability by packaging this in a broader heating service model such as heat-as-a-service. Future research could explore whether greater reduction in indoor temperatures during peak periods and more allowance for pre-heating could provide significantly more flexibility, however this would need to consider the incentivisation and service proposition and business model structure to be successful. Ways of incentivising battery uptake among households should also be considered and compared to alternatives such as commercial scale batteries connected at the distribution substation level.
- **Value the temporary nature of heat flexibility**. The simple cost benefit analysis shows that the cost benefit out to 2050 is often marginal, especially if a single network reinforcement option is selected. However there is considerable uncertainty over exactly how and when electricity loads will increase, and whether there will be other innovations which can help reduce these loads. A heat flexibility solution provides the opportunity for expenditure only when the mitigation is needed and is incremental, unlike large

capital expenditure on reinforcement. Therefore WPD need to account for the additional value that this flexibility-first approach provides over reinforcement.

Incentivising customers is central to obtaining heat flexibility. WPD should explore how they can incentivise customers in the most cost effective way to achieve the required level of uptake. This will mean looking at the broader values available in customer propositions and engaging with other players in this sector:

- **Explore the potential offered by tariff structures that charge residential customers according to their peak power demands.** This is the approach taken by Norway, Flanders and the Netherlands and could implement the simulated electricity capacity supply limits, the benefits of which are outlined above. Appropriate tariff structures could also mitigate the risk of a large number of heat pumps all generating hot water in the same narrow period, causing a peak in demand. Further research could also explore the impact of different electricity tariff structures on battery discharge profiles to maximise the reduction in peak demand.
- **Explore new ways of incentivising diversity**. Appropriate tariff structures are one way of incentivising increased diversity, however other methods should be explored as more and more homes are equipped with heat pumps and intelligent storage devices all responding to the same price signals. Additional flexibility measures could actually have an adverse impact on peak demands by adding additional loads and shifting these peaks from high to low price periods.
- **Explore how flexibility fiscal incentives for behind the meter battery storage and / or larger thermal stores (such as phase change material batteries) can be reduced.** These measures are the most effective at reducing peak loads and mitigating large scale reinforcement but could be relatively high cost to incentivise. A reduction in the cost of incentives required to access storage capacity will likely come from the development of novel commercial methods that maximise participation in domestic DSO flexibility service, and the customer propositions and associated business models which feed into these services, such as heat-as-a-service. Work being undertaken by WPD's EQUINOX project exploring these methods will therefore be valuable in progressing towards this goal.

There are some easy wins by simply commissioning controls in a suitable manner:

- **WPD should become active in supporting policy and regulations development in the heating controls arena.** The impact of correctly designed and regulated controls requirements could be highly beneficial to WPD and WPD should consider the role in driving policy and regulations. One example of this is including a process to ensure that load shifting is diversified to prevent the creation of new extreme peaks caused by all customers shifting to the same time period.
- **Engage more with the heating engineer / installer / controls sector and standards setting for heating controls**. Shifting the timing of hot water generation is a relatively easy, low-cost way of reducing peak demands. WPD should therefore explore how it can facilitate this through engagement with the heating installers to influence the controls configuration.

Heat flexibility will only be one part of the solution and network flexibility may also be required:

- **Investigate other ways of relieving more capacity in the networks – using 'network side' flexibility approaches alongside demand side flexibility approaches.** The combination of and interaction between network side approaches such as variable ratings, and demand side flexibility approaches as looked at within this project, is being explored by ENWL in Smart Heat.

4.4. Broader implications of Peak Heat

Whilst much flexibility can be gained in average winter conditions, results show that demand side flexibility measures are not going to be a silver bullet in 1-in-20 cold conditions. New peak heating loads from the levels of electrification of heat forecasted are highly likely to require significant network upgrades.

Most existing analysis of heat electrification has considered average winter conditions. Whilst gas networks have to ensure there is adequate capacity for severe 1-in-20 peak conditions due to reliance on gas for heating, this has not been an issue for electricity networks where very cold conditions only have a small impact on loads due to the small penetration of electric heating. The need to cater for 1-in-20 conditions will bring a number of requirements to load forecasting and planning, including:

- Consideration of weather conditions and the connection of these conditions to peak demand in business planning and network reinforcement.
- Consideration of customer impacts where there are constraints or failures in peak winter conditions, and how customers can be provided with a resilient solution.

Whilst there are some uncertainties around future heat decarbonisation pathways in the UK, (particularly with uncertainties around the role of hydrogen), it is highly likely that electrification of heat will be a major component, especially in off-gas grid areas, with heat pumps the predominant solution. The large scale reinforcement required under scenarios of high heat pump uptake to meet peak winter conditions will mean either considerable additional cost due to reinforcement, and/or due to high incentive costs to access existing heat flexibility within customer homes. It is therefore likely that a range of options will need to be pursued by DNOs to ensure customer’s heat demands can be reliably met in peak winter conditions.

Appendix A: Additional CBA assumptions

Assumption	Value	Notes
Discount rate	3.5%	Ofgem CBA rate used
Capitalisation rate	85%	Ofgem rate used
Pre-tax WACC	4.2%	Ofgem rate used
Assumed network asset life	45 years	Ofgem assumption
Incentive cost per customer for relaxing temperature requirements by 1C at peak times	£67.25	The cost for this measure guided by existing customer research on expected customer renumeration for controlling their load more flexibly. Smart Heat customer research showed that financial reward was the most popular incentive, with reduction in heating bill being the preferred type. 79% of customers would be happy with a 10% or less reduction on their bill (35% happy with 5% or less reduction). According to the Department for Business, Energy & Industrial Strategy (BEIS), the average household uses 3,731 kWh per year. Assuming electricity costs of 17.4p/kWh then annual cost is £649 Assuming an average home requires around 12,000 kWh of heat per year and has a heat pump with CoP of three would use 4,000 kW of electricity annually. Assuming electricity costs of around 17.4p/kWh then a heat pump's running costs could be around £696 per year. Total cost is therefore £649 + £696 = £1345. Assume therefore incentive is 5% of this - £67.25
Incentive cost for hot water generation flexibility	£34	Assume that to heat up their hot water tank more flexibly (i.e. program their hot water generation to occur outside of usual peak periods) would require lobbying HP manufacturers to train / advise installers to program hot water generation differently.

		However no data exists on this, so as a proxy we have assumed, per customer, a cost equal to 1 hour of the average hourly rate of a heating engineer. Assume this is a one-off cost occurring at the time the customer gets their heat pump installed
Incentive cost for electric battery flexibility	£191.00	Used Bid data on the Piclo platform from residential battery aggregators Moixa, Social Energy and Powervault to give proxy for cost to DNO of 'buying' battery capacity at peak times. Analysis of this data gives a Min (£0.31/ customer/ h), Median (£1.85/ customer/ h) and Max (£12.07/ customer/ h), Average of £1.91/ customer/h, based on the following assumptions: • Avg. domestic battery capacity of 5kWh • Avg. discharge duration of 2 hours • Calculating the maximum output (based on the bidder’s offered capacity and the maximum run time) and then using that output to determine the number of customers who will be discharging their battery during peak time (maximum output/ avg. domestic battery output). This doesn’t consider the number of customers an aggregator has, just the number of customers the aggregator is paying to meet the required demand. • Taking 30% off the cost per customer, which is based on the revenue sharing model for Social Energy. Looking at battery scenarios across archetypes, there is an average of 49 overloaded hours across all substation archetypes across the two cold month periods. Given that the heating season lasts about four to six months, it was estimated that there would be about 100 overloaded hours in a year. Assume that per customer then on average WPD will pay £1.91*100 = 191.00
Incentive cost for buffer tank flexibility	£14	Used Bid data on the Piclo platform from residential battery aggregators Moixa, Social Energy and Powervault to give proxy for cost to DNO of ‘buying’ battery capacity at peak times. Updated assumptions to give proxy for buffer tanks Analysis of this data gives a Min (£0.02/ customer/ h), Median (£0.14/ customer/ h) and Max (£0.91/

	customer/ h), Average of £0.14/ customer/h, based on the following assumptions: • Avg. buffer capacity of 3kWh • Avg. discharge duration of 0.25 hours (15 mins) • Calculating the maximum output (based on the bidder's offered capacity and the maximum run time) and then using that output to determine the number of customers who will be discharging their buffer during peak time (maximum output/ avg. domestic buffer output). This doesn't consider the number of customers an aggregator has, just the number of customers the aggregator is paying to meet the required demand. • Taking 30% off the cost per customer, which is based on the revenue sharing model for Social Energy. Looking at buffer scenarios across archetypes, there is an average of 52 overloaded hours across all substation archetypes across the two cold month periods. Given that the heating season lasts about four to six months, it was estimated that there would be about 150 overloaded hours in a year. Assume that per customer then on average WPD will pay £0.14*100 = 14