Leppington Energy Community Interest Scheme

Energy Options Appraisal

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1 Executive Summary

BuroHappold were commissioned to undertake a study into potential low carbon heating and power solutions for the rural village of Leppington which consists of 30 houses and a dairy farm.

Heating to properties is predominantly provided through individual oil-fired boilers, while power is provided via the NPG grid network. The farm has been identified as having good potential to host large scale energy plant, with high interest expressed form the farmer as the landowner.

Following a technology assessment, six scenarios were taken forward for energy modelling and techno-economic assessment to assess the benefits from the perspective of both a Special Purpose Vehicle (SPV) and village residents.

The scenarios were as follows:

- **Scenario A** – Decentralised ASHPs installed at building level
- **Scenario B** - Decentralised ASHPs installed at building level + Optimised renewables Installed at Farm
- **Scenario C** - Centralised ASHP + AD driven biogas CHP installed at farm serves village heat network. CHP serves energy centre demands with excess exported back to grid
- **Scenario D** - Centralised ASHP installed at farm serves village heat network. Optimised renewables at farm serve energy centre demands with excess power exported back to grid
- **Scenario E** - Centralised ASHP installed at farm serves village heat network. Large scale renewables at farm serve energy centre demands with excess power used to generate hydrogen or be exported back to grid
- **Scenario B+** - Considers deployment of large-scale renewables at the farm and supply of renewable power to nearby properties within villages which would transition to decentralised ASHP's (similar to Scenario A/B)

Techno-economic results indicate that centralised heating solutions and the development of a heat network to serve the village are not economically feasible, even when considering subsidy, due to the low heat density of the village.

Decentralised ASHP systems show greater promise to deliver long term energy, carbon and cost savings to residents, as can be seen in Figure 1—1 which presents cost savings to residents for decentralised scenarios A, B & B+. Further savings would be achieved if access to government subsidy schemes were secured.

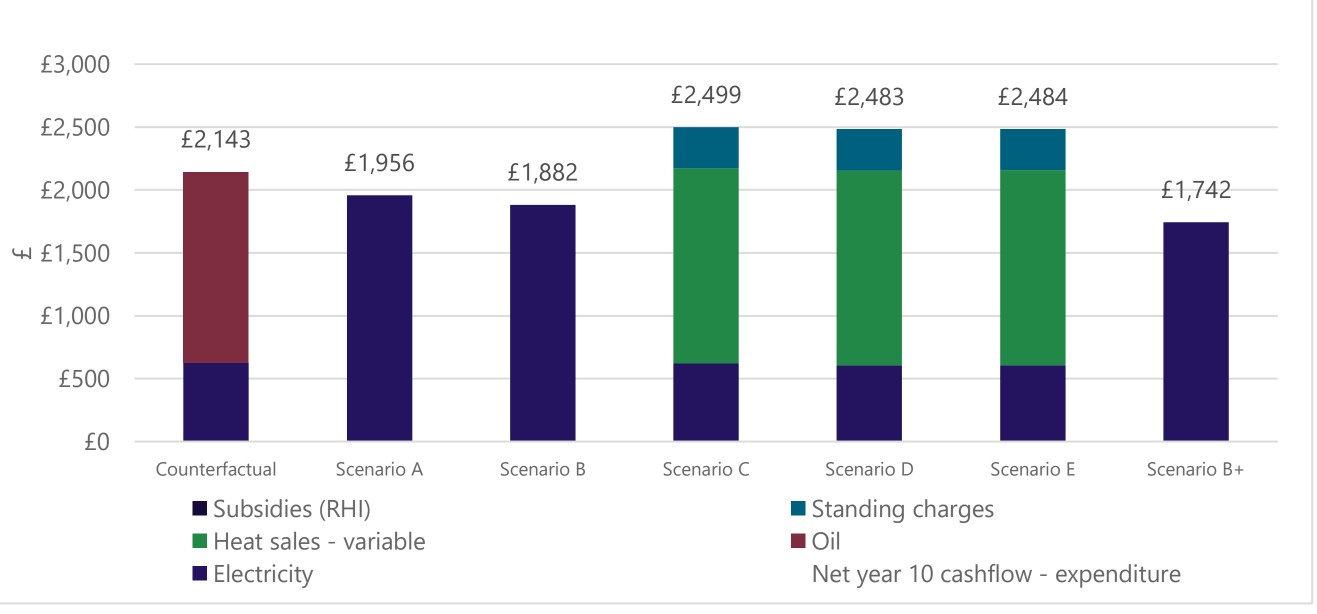

Figure 1—1 - Annual Expenditure Comparison for Households

This study finds that 3 of the 6 modelled scenarios achieve positive cashflow during year on year operation, being scenarios B / B+ and scenario E. These positive cash flows become more appealing when considering implementation of RHI or other government subsidy to help justify the investment case. When considering the NPV of each scenario over a 40-year timeframe, no scenario achieves a return on investment with positive cashflow scenarios B & E showing relatively static NPV's.

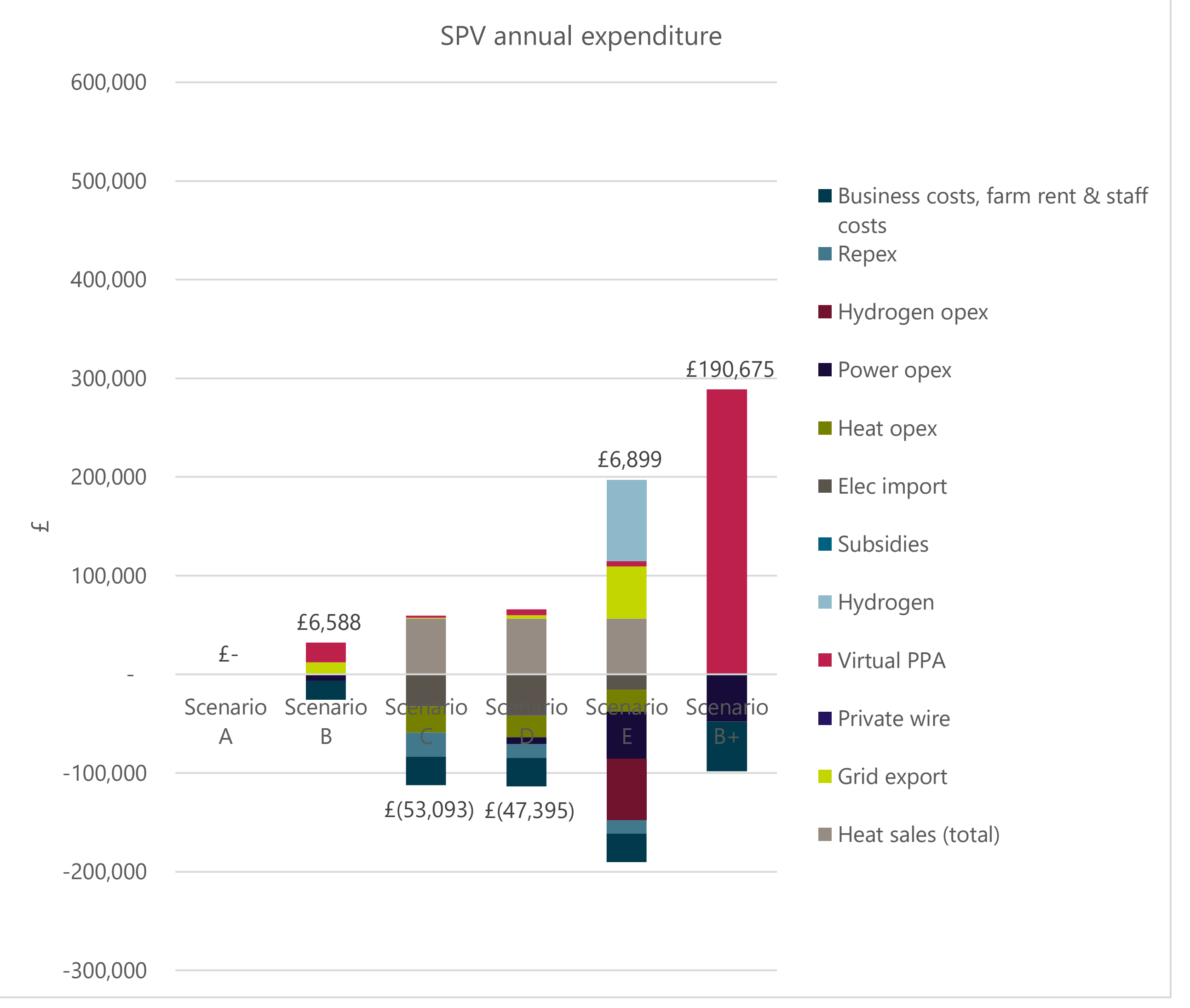

Figure 1—2 SPV Annual Expenditure Comparison

Scenario B+ achieves ~40% return on the initial investment which suggests that, with appropriate low interest funding and subsidy such a scheme could be taken forward for more detailed investigation.

When considering power exported from renewables installed at the farm, securing the right PPA agreements and providing the option for local ownership of the scheme in conjunction with supply local residents will result in greater income for an SPV due to the higher sales price vs. standard grid export rate as well as directly contribute to the affordability and accelerated transition of low carbon heat and power in local communities.

Given the suitable land availability at the farm, the willingness of the landowner to develop a renewable energy scheme, and the level of interest from key village stakeholders a sensible next step would be to determine local community interest in supporting the development of a community energy SPV for both the development of the renewable energy system and procurement of local energy.

2 Site Appraisal

2.1 Overview

The village of Leppington in Northern Yorkshire has been identified as a potentially suitable site for the deployment of low carbon power and heating solutions. There are 30 homes within the village as well as a dairy farm at the north west corner. The village is not connected to the gas grid and most properties utilise oil fired boilers for space heating and Domestic Hot Water (DHW) production. There is a 100 kWth biomass boiler which serves the farm.

There is a large amount of land area owned by the farmer which could be utilised for an energy centre or to deploy renewable power solutions. Farmer owned land areas are presented in Figure 2—1, as denoted by the red line boundary. Initial analysis indicates good potential for deployment Solar PV and wind turbines within these land areas.

A Special Purpose Vehicle (SPV) community energy organisation could be conceived to design, build, own and operate a centralised energy system located at the farm which would hold a leasing arrangement with the farm owner. A variety of commercial models are available which include the opportunity for village inhabitants to become shareholders in any SPV that is set up to deliver a centralised scheme.

The options for both generation of power and heat have been assessed based on a centralised solution at the farm. A new District Heating Network would be required to deliver heat generated at the farm to dwellings within the village. The required heat network length and annual demand for heat at each dwelling yields low line densities (>2MWh/m) which mean a heat network would require significant external funding to justify. This is felt to be less viable than a distributed system for heat based on current pricing and subsidy structures.

There is an existing constraint on the power import and export capacity at the village due to the LV distribution substation on Northern Power Grid's network. Power is provided at present by a single 92kVA pole mounted transformer with LV power being supplied to dwellings via overhead and buried cabling. The village is supplied on 2 phases. At least two properties currently utilise rooftop Solar PV panels for supplementary power.

There is a 60A (28kVA) connection from the pole mounted transformer to the farm which will require upgrade to a more substantial substation to facilitate greater import / export capacity. The transformer is served from a primary substation located to the north in the town of Malton.

Discussions with the DNO Norther Power Grid (NPG) revealed that implementing G100 Export limitation device to LV connection with large scale renewable generation is possible but NPG will need to assess as part of connection agreement.

Figure 2—1 - Leppington Village (Source: Google Maps)

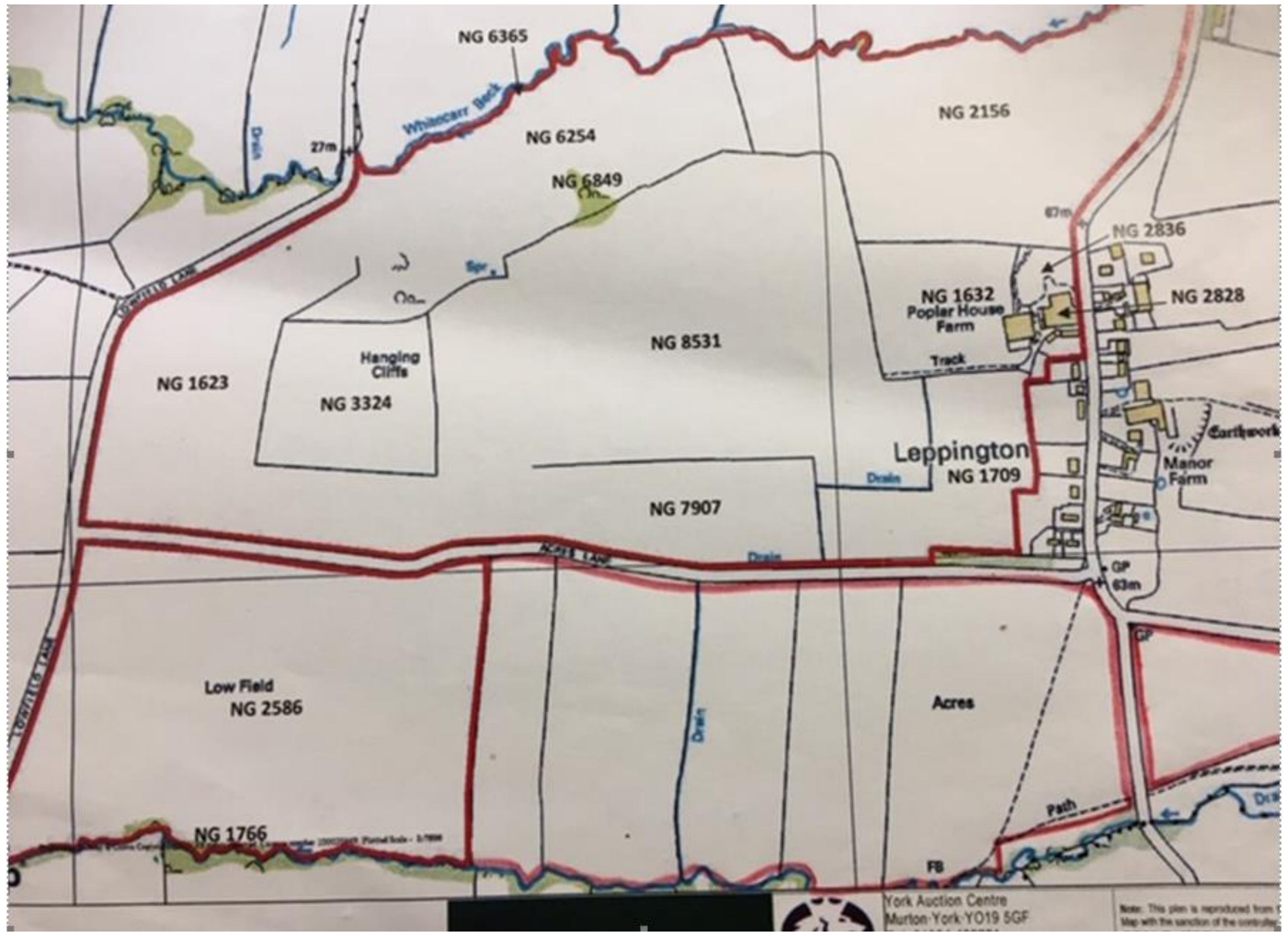

Figure 2—2 Farmer Owned Land (Source: Google Maps)

3 Community Engagement

A questionnaire was distributed to the village at the outset of the project to gauge resident interest in deployment of low carbon power and heating solutions. A copy of the questionnaire is included within Appendix D. The responses of the questionnaire have allowed more detailed modelling to take place with respect to actual heating and power demands including factoring in current bill payments to considerations around the sale price for heat and power. This allows a full assessment of options to reduce resident bills and protect them from future oil price and carbon tax adjustments. A summary of the responses is included in Table 3—1.

The responses indicated a general preference towards sustainable and affordable heating and power supply with an average interest of 4 out of a maximum of 5 (Q1). At present no objections have been raised towards pursuing a community wide scheme.

Key stakeholders including the local MP, the chair of the Scrayingham Parish Council and the Farmer who owns a significant portion of land around the village are onboard with developing potential schemes and have engaged well during site meetings. Both the farmer and residents are well aware of the potential commercial benefits of involvement in a Community Interest Company (CIC) to deliver low carbon energy solutions for the village. The next step will be to engage residents in a town hall meeting environment to discuss scenarios identified as having significant potential to take forward to more detailed stages of design and planning.

Table 3—1 Questionnaire Responses

	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12	Q13	Q14	Q15	Q16
	3	Biomass	22	y	c	yes	no	-	no	£5,000	£7,500	no	no	?	7	1
	4	oil	12	y	c	yes	no	-	no	£1,400	£612	no	no	?	5	3
	4	oil	20	y	b	yes	no	-	no	£3,000	£900	no	yes	yes	4	3
	5	oil	20	y	c	yes	no	-	no	£1,200	£1,100	yes	yes	yes	5	4
	5	oil	11	y	b	yes	no	-	no	£900	£1,100	no	no	yes	4	3
	5	oil	9	y	c	yes	no	-	no	£250	£710	no	no	no	3	5
	3	oil	6	y	c	yes	yes	3	no	£500	£300	no	no	no	3	4
	5	oil	19	y	c	yes	no	-	no	-	£800	?	no	?	5	4
	5	oil	6	y	c	yes	no	-	no	£500	£600	no	no	yes	4	3
	5	gas	18	y	c	yes	no	-	no	£1,560	£900	no	yes	yes	4	2
	3	gas	15	y	c	yes	no	-	no	£1,000	£600	yes	no	?	5	3
	3	oil	10	y	c	yes	no	-	no	£500	£500	no	no	no	3	3
	3	oil	8	y	c	yes	no	-	no	£600	£460	no	yes	yes	2	3
	3	oil	5	y	d	yes	yes	?	no	£700	£650	no	yes	yes	2	5
	3	oil	U/F htg	n	N/A	N/A	no	-	no	£1,500	£936	no	yes	yes	3	5
	3	oil	13	y	c	yes	no	-	no	£1,000	£1,000	yes / no	no	?	4	3
Ave.	4		13							£1,307	£1167				4	4

4 Community Benefits

4.1 Benefits to Leppington

The identified benefits to the village include the freedom to move away from fossil fuelled heating towards low carbon solutions and providing the real opportunity for a net zero carbon community that is resilient to fluctuating energy prices. Techno-economic modelling of the scenarios has determined significant opportunities around the utilisation of high efficiency heat pumps which could realise significant annual cost and carbon savings on energy bills against the counterfactual oil-fired boiler systems. Through encouraging residents to upgrade properties to incorporate lower temperature heating circuits this would likely lead to further long-term reductions in energy costs, while increasing property value. This should be considered in conjunction with the opportunity to procure local renewable energy at a reduced cost through a community energy arrangement. This includes the opportunity for community members to directly participate in the ownership of the renewable scheme and realise a return as well as benefit from lower energy costs.

The use of local land and appropriate commercial arrangements with the landowner will further add value by ensuring lower scheme land rental costs. The farm itself will also benefit from lower cost of energy as well as rental yield which adds additional value in supporting local agriculture.

4.2 Wider Benefits

Whilst the initial focus of the study was on the decarbonisation of heat in Leppington and the viability of renewable generation at the farm, the study was widened to consider wider regional opportunities.

Should the identified land area at the farm be developed fully to incorporate large scale Solar PV and wind turbines which would provide sufficient energy over and above the demand of Leppington, it is viable that that other nearby villages would then have the opportunity to also directly benefit from accessing lower cost zero carbon energy off the generation plant through the same commercial mechanisms.

An initial analysis has identified that the nearby villages of Scrayingham, Ackland and Leavening could benefit from such scheme. These locations share a similarity to Leppington in that they are not connected to the existing gas grid. Capacities within distribution lines and local substations at Maltan and Sherriff Hutton will need to be determined through further consultation with NPG as a transition to heat pump led systems within these areas could lead to a significant increase in power demands. Network modelling will be required but it is conceivable that by utilising local generation in conjunction with heat demand, overall system demand at the primary substations could be reduced, releasing head room for uptake of further low carbon solutions in the area. This opportunity requires further work recommended in the next phase of design whereby consultation with NPG is required.

A potential solution which may avoid the need for costly grid upgrades could be to implement Demand Side Response (DSR) to control individual heat pump plant in conjunction with electricity and/or thermal storage systems to ensure threshold power capacities of the grid are not exceeded.

Significant job creation is expected though deployment the large-scale deployment of renewables, implementation of heat pumps within properties as well as building level upgrades to incorporate such systems. A number of local contractors within the area have been identified.

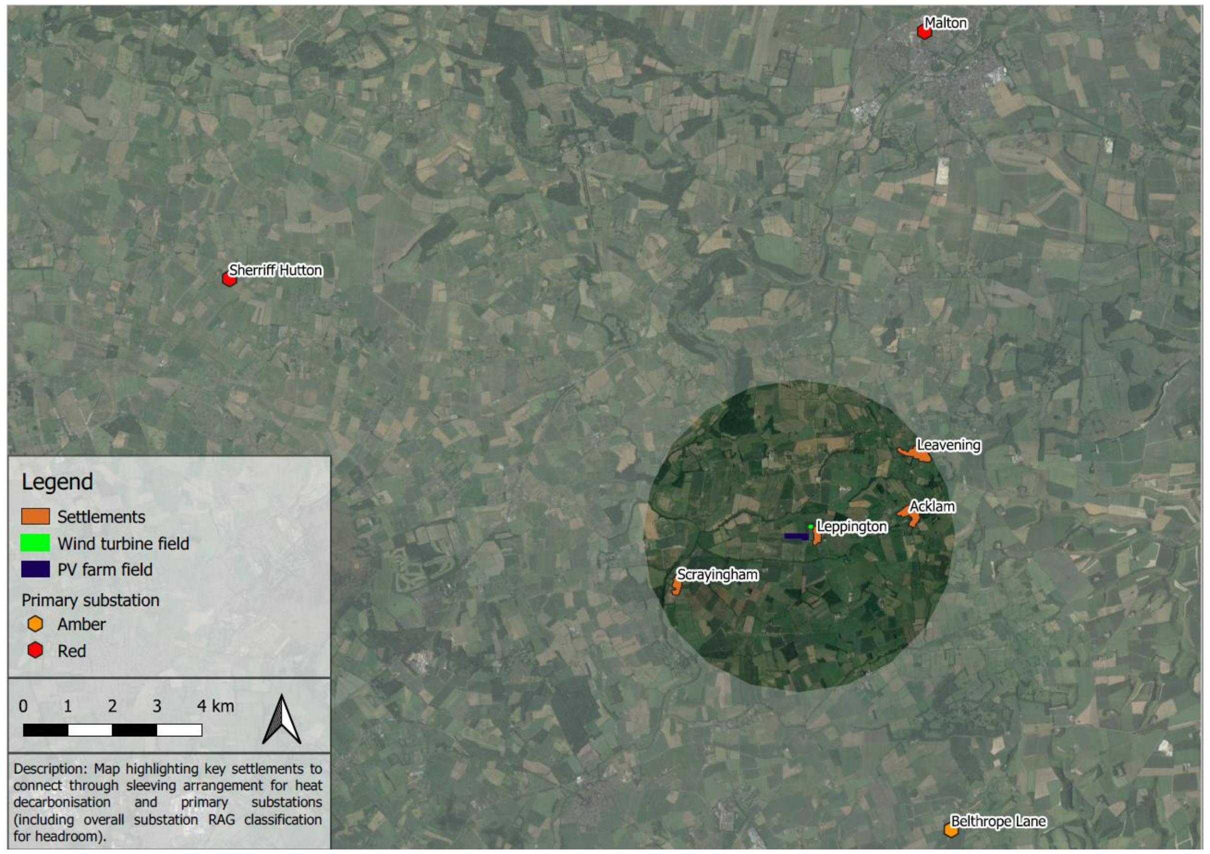

Figure 4—1 - Primary Substation Locations / Nearby Communities

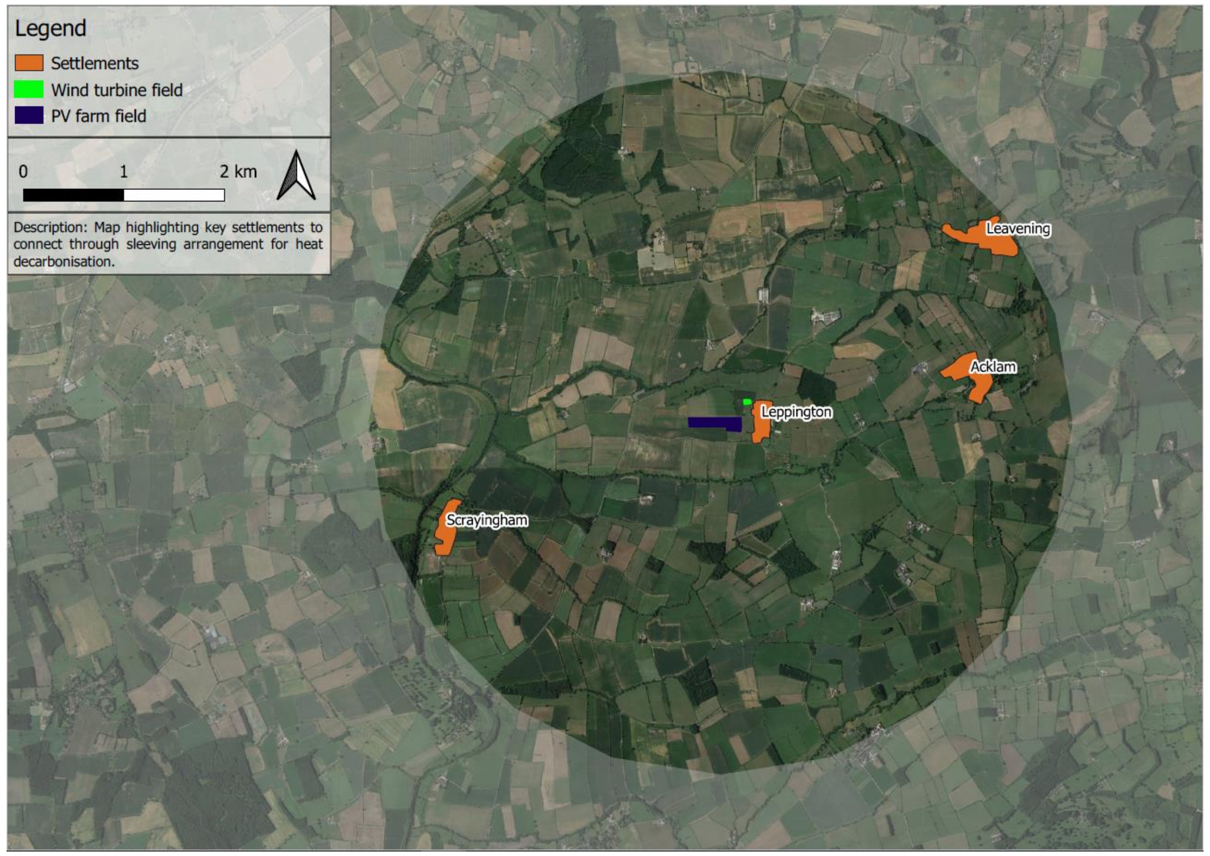

Figure 4—2 - Communities within 2km radius of Leppington

5 Energy Demands

5.1 Power

Total annual and peak power demands have been calculated as presented in Table 5—1 based on returned questionnaires. Averages have been assumed for units where no information was received.

Table 5—1 - Power Demands

Calculation Method	Unit	Annual Electricity Bill (£)	Annual Electricity Consumption (kWh)	Peak Electricity ADMD* (kW)
Survey Returned	Farm	£7,500	39,474	20
Survey returned	House 1	£612	3,221	2
Survey returned	House 2	£900	4,737	2
Survey returned	House 3	£1,100	5,789	2
Survey returned	House 4	£1,100	5,789	2
Survey returned	House 5	£710	3,737	2
Survey returned	House 6	£300	1,579	2
Survey returned	House 7	£800	4,211	2
Survey returned	House 8	£600	3,158	2
Survey returned	House 9	£900	4,737	2
Survey returned	House 10	£600	3,158	2
Survey returned	House 11	£500	2,632	2
Survey returned	House 12	£460	2,421	2
Survey returned	House 13	£650	3,421	2
Survey returned	House 14	£1,000	5,263	2
Based on Average	House 15	£745	3,919	2
Based on Average	House 16	£745	3,919	2
Based on Average	House 17	£745	3,919	2
Based on Average	House 18	£745	3,919	2
Based on Average	House 19	£745	3,919	2
Based on Average	House 20	£745	3,919	2
Based on Average	House 21	£745	3,919	2
Based on Average	House 22	£745	3,919	2
Based on Average	House 23	£745	3,919	2
Based on Average	House 24	£745	3,919	2
Based on Average	House 25	£745	3,919	2
Based on Average	House 26	£745	3,919	2
Based on Average	House 27	£745	3,919	2
Based on Average	House 28	£745	3,919	2
Based on Average	House 29	£745	3,919	2
Survey Returned	House 30	£936	4,926	4.8
	Total	*£29,834*	*157,032*	*83*

*After Diversity Maximum Demand (ADMD)

5.2 Heating

Total annual and peak heating demands have been calculated as presented in Table 5—1 based on returned questionnaires. Averages have been assumed for units where no information was received.

Table 5—2 Heat Demands

Calculation Method	Unit	Annual Heating Bill (£)		Heating Fuel Type	Annual SH + DHW** Demand (kWh)	Peak Diversified SH + DHW (kW)
Survey Returned	Farm	£	5,000	Biomass	62,742	22.5
Survey returned	House 1	£	1,400	oil	39,011	10.3
Survey returned	House 2	£	3,000	oil	83,595	14.4
Survey returned	House 3	£	1,200	oil	33,438	14.4
Survey returned	House 4	£	900	oil	25,078	9.8
Survey returned	House 5	£	250	oil	6,966	8.8
Survey returned	House 6	£	500	oil	13,932	7.2
Survey returned	House 7	£	1,008	oil	28,101	13.9
Survey returned	House 8	£	500	oil	13,932	7.2
Survey returned	House 9	£	1,560	gas	27,260	13.4
Survey returned	House 10	£	1,000	gas	17,474	11.8
Survey returned	House 11	£	500	oil	13,932	9.3
Survey returned	House 12	£	600	oil	16,719	8.3
Survey returned	House 13	£	700	oil	19,505	6.7
Survey returned	House 14	£	1,000	oil	27,865	10.8
Based on Average	House 15	£	1,008	oil	28,101	10.5
Based on Average	House 16	£	1,008	oil	28,101	10.5
Based on Average	House 17	£	1,008	oil	28,101	10.5
Based on Average	House 18	£	1,008	oil	28,101	10.5
Based on Average	House 19	£	1,008	oil	28,101	10.5
Based on Average	House 20	£	1,008	oil	28,101	10.5
Based on Average	House 21	£	1,008	oil	28,101	10.5
Based on Average	House 22	£	1,008	oil	28,101	10.5
Based on Average	House 23	£	1,008	gas	17,622	10.5
Based on Average	House 24	£	1,008	gas	17,622	10.5
Based on Average	House 25	£	1,008	oil	28,101	10.5
Based on Average	House 26	£	1,008	oil	28,101	10.5
Based on Average	House 27	£	1,008	oil	28,101	10.5
Based on Average	House 28	£	1,008	oil	28,101	10.5
Based on Average	House 29	£	1,008	oil	28,101	10.5
Survey Returned	House 30	£	1,500	Power (Heat Pump)	Not included	Not Included
	Total	*£*	*35,738*		*830,108*	*326*

**Space Heating and Domestic Hot Water

6 Technology Appraisal

6.1 Overview

In order to determine the appropriate low carbon heating and power solutions, a technology assessment has been undertaken. The assessment considers both centralised and decentralised solutions.

6.2 Village Wide Heat Network

A heat network would require significant financial subsidy in order to economically justify which is a direct result of low heat density within the village. However, if a centralised energy centre is to be considered at the farm, a buried heat network will be required to deliver heat to the village. The proposed network routing is presented in Figure 6—1.

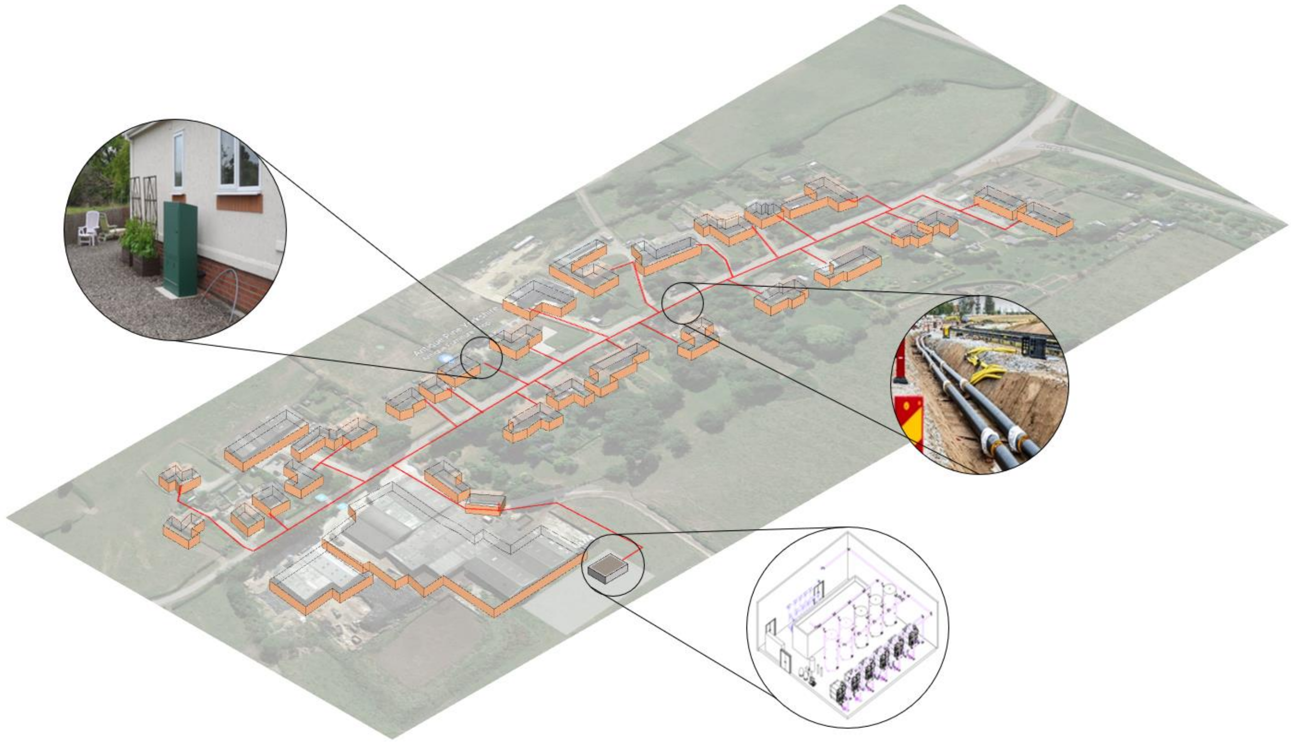

Figure 6—1 - Village Heat Network

Heating Interface Units (HIU's) would be required at dwelling level to connect up existing development, an example pictured as the green box in Figure 6—1.

A typical interface unit would consist of a single heat exchanger and heat meter. Existing Domestic Hot Water (DHW) cylinders that have been noted as being present within each dwelling could remain in situ with immersions heaters as a backup supply.

In addition to centralised thermal storage located at the farm, heating the DHW tanks could be timed to benefit the overall system, avoid coincident peaks and benefit the operation any heat pumps installed at the energy centre through utilising grid power during cheaper periods.

The proposed connection arrangement is presented in Figure 6—2.

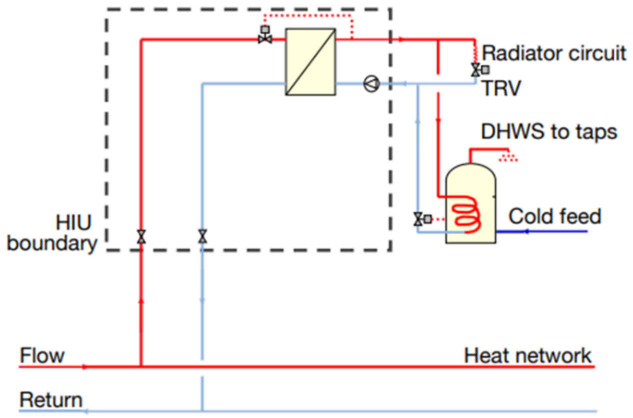

Figure 6—2 Indirect Space Heating & Hot Water Cylinder Connection (Source CP1:2015)

6.3 Anaerobic Digestion + CHP

Technical potential to deploy AD + CHP plant to provide a renewable source of eating and power to the village has been identified, however no subsidies are known to be available to bolster the economic case.

The dairy farm located to the North of the village has around 160 cows in milk with around 160 followers.

There is an existing slurry pit that could be utilised to provide feedstock input for an anaerobic digestor, which could be used to produce biogas and drive a Combined Heat & Power (CHP) unit.

Initial calculations indicate that a biodigester of ~200m3 capacity with an annual biogas yield of ~77,000 m3 would be feasible given the number of dairy cows. This would equate to a CHP sized at ~30kWe.

There is good land availability to deploy AD plant adjacent to the existing slurry pit.


Figure 6—3 Slurry pit and land available for AD deployment

Heat generated from the CHP unit could be used as part of the biodigester process as well as a network supplying heat to the village. Further heat supply from another source (i.e. Heat Pumps) would be required to meet peak / annual heat demands.

CHP generated power could help meet power demands at the farm with excess power pushed back to the grid. This would require grid reinforcement at the farm. Sleeving arrangements with the DNO could be secured to virtually sell power back to the village. From conversations with the DNO (NPG), a new metered RMU up to 1 MVA at the farm would likely be required to provide sufficient capacity and act as a backup power supply. This is assuming that centralised heat pumps at the farm would be required to provide supplementary heat to a village heat network. Implementation of this substation is understood to cost approximately £300,000.

Further feedstock availability within the region has been identified including additional slurry from nearby dairy farms as well as potential to supplement with local garden and food waste. Incorporation of these feedstocks would allow for a larger digestor deployment as well as a greater annual biogas yield and therefore a larger CHP unit providing heat and power to the village. However, given the lack of clarity on whether additional feedstocks could be secured, they have not been considered within the AD digestor sizing and resultant biogas yield. In addition, it has been noted slurry only digestors tend to run at around 99% efficiency with the introduction of different feedstocks adding significant risk and lowering process efficiencies to ~60%.

6.4 Heat pumps

Heat pumps have been identified as having good potential. Heat pumps could either be deployed centrally within an energy centre (located at the farm) and serve a village wide heat network or be installed at an individual property level (decentralised) and utilise heat from either the ground or air as an input source. For the purposes of this study air source heat pumps (ASHP's) have been considered the most viable technology due to their lower installation costs.

6.4.1 Centralised

Centralised systems offer benefits of slightly higher overall plant running efficiencies and present an opportunity for an SPV owned and operated solution for the village, supplying heat via a heat network.

Heat pumps tend to operate more efficiently at lower delivery temperatures and so would work best if combined with CHP or biomass plant which produce higher temperatures. Through temperature blending, delivery temperatures that align with existing high temperature heating systems could be achieved, largely offsetting the need for heating system upgrades at a building level. Renewable power from the CHP units could also be used to drive the heat pumps, achieving significant carbon savings.

In order to provide sufficient capacity for the peak heating demands, ASHP's with a capacity of ~350kW have been considered, with a peak power input requirement of ~120kW.

Heat pumps would require a grid connection capable of providing the required input power in absence of the CHP power, as such grid reinforcement at the farm would be required. Similar to the AD + CHP scenario a new metered RMU up to 1 MVA at the farm would likely be needed to provide sufficient capacity at a cost approximately £300,000.

6.4.2 Decentralised

Decentralised heat pump systems can offer significant cost savings over centralised options when the heat density of the end users is insufficient to justify the CAPEX / OPEX of installing a heat network.

There is however less of an opportunity for an SPV to become involved to own and operate systems given the decentralised nature of the plant. However, there is an emerging interest in this area from "Heat as a Service" providers who will package up heat pump, retrofit and energy provision offerings supported by attractive rates of finance.

Heat pumps installed at a building level are likely to require upgrades to the buildings themselves to allow for lower supply temperatures which include improvements to the building envelope to reduce heat losses as well as provision of larger panel radiators and supplementary equipment. These costs could be up to ~£20,000 / dwelling to incorporate. Funding which is accessible through the Green Homes Grant allows up to £5,000 (or £10,000 for low income households) towards the cost of energy efficiency improvements. Improvements must be completed by 31st March 2021 under the current scheme.

Heat pumps of between 10 – 16kWth would be required at each property if the village we to implement decentralised solutions. This would put additional power demand requirements on the existing LV grid infrastructure. Typically, when individual dwellings are considering standalone heat pumps, an application to DNO is required to gain approval to ensure there is sufficiency capacity in the grid. A joint application from the village may be feasible to achieve DNO approval with grid upgrade capacity being undertaken at the cost to the DNO.

Figure 6—4 Decentralised (left) vs. Centralised (right) ASHP (Source: https://iheatltd.co.uk/)

6.5 Biomass

There is an existing HERZ Firematic 100kWth biomass boiler installed at farm which is currently eligible for RHI.

Integration of this plant into a centralised solution at the farm has been considered however available capacity year-round cannot be guaranteed due to current farm uses.

Figure 6—5 - 100kW Biomass Boiler & pellet hopper

Incorporation of any heat from the biomass boiler into the heat network would require metering arrangements in place with an SPV owning and operating the plant at the farm with high grade heat availability from the biomass boiler being useful when there is no supply from a CHP led scenario.

6.6 Electric Boilers

Electric boilers have been considered as a substitute for centralised or decentralised heat pump solutions or as a backup supply for other plant. Given the significant increases in efficiency that can be achieved through utilisation of heat pumps, as well as the improved carbon saving potential, electric boilers have been disregarded as a potential solution.

6.7 Hydrogen Electrolysers

The production of hydrogen has been considered which could be generated through electrolysis via excess renewable power generation installed at the farm. Containerised electrolyser and hydrogen storage solutions can be deployed which are available through companies such as ITM Power.

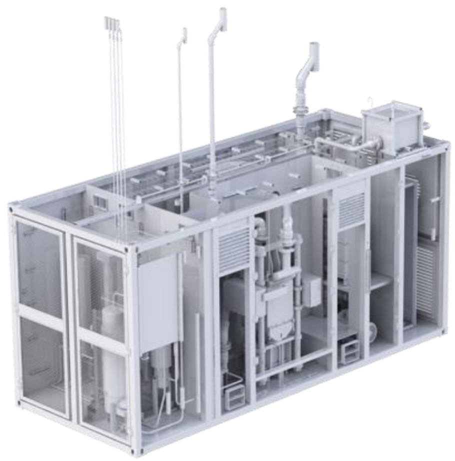

Figure 6—6 ITM HGas1SP Electrolyser (Spurce https://www.itm-power.com/products)

The hydrogen would require export from site for use with a local or national demand. The Yorkshire ambulance service has been identified as a potential end user as they look to decarbonise their ambulance fleet, with electric vehicle recharge times being restrictive to vehicles which must be available constantly.

6.8 Thermal Storage

Thermal storage allows the gap to be bridged between optimum run times for heat generating plant and end user demand. Further cost savings can also be achieved when considering heat pumps running during periods of cheaper grid connected power availability (i.e. overnight).

Bother centralised and decentralised thermal storage solutions have been considered as part of this study.

6.9 Solar PV

Solar power could provide direct energy input into energy centres installed at the farm, push power back into the grid (for use nationally or within the village through a virtual PPA) or be used to generate hydrogen.

Grid reinforcement at the farm would be required to accommodate any requirement to push power back to the grid.

Given the age and condition of many of the existing roofs within the village, as well as the predominant east – west roof slope profiles, a centralised solution at the farm has been considered as the preferred solution.

Good potential for deployment of Solar PV has been identified given the unobstructed south facing land availability at the farm which could be used to deploy large scale arrays. This area is presented in Figure 6—7. Initial analysis suggests up to 3MW of solar PV could be deployed in this location.

The aspect of the field slope is considered ideal for PV, being south facing. The area is closer to the farm is less suited as shown in Figure 6—8. The slope angle of the is also well suited to PV installation as shown in Figure 6—9. Generally, slope angles of under 5 degrees are preferred but this is in part to overcome issues of slope aspect. As the only area of the field which is relatively steep (i.e. the western portion) is also south facing slope, angle is not seen as a constraint.

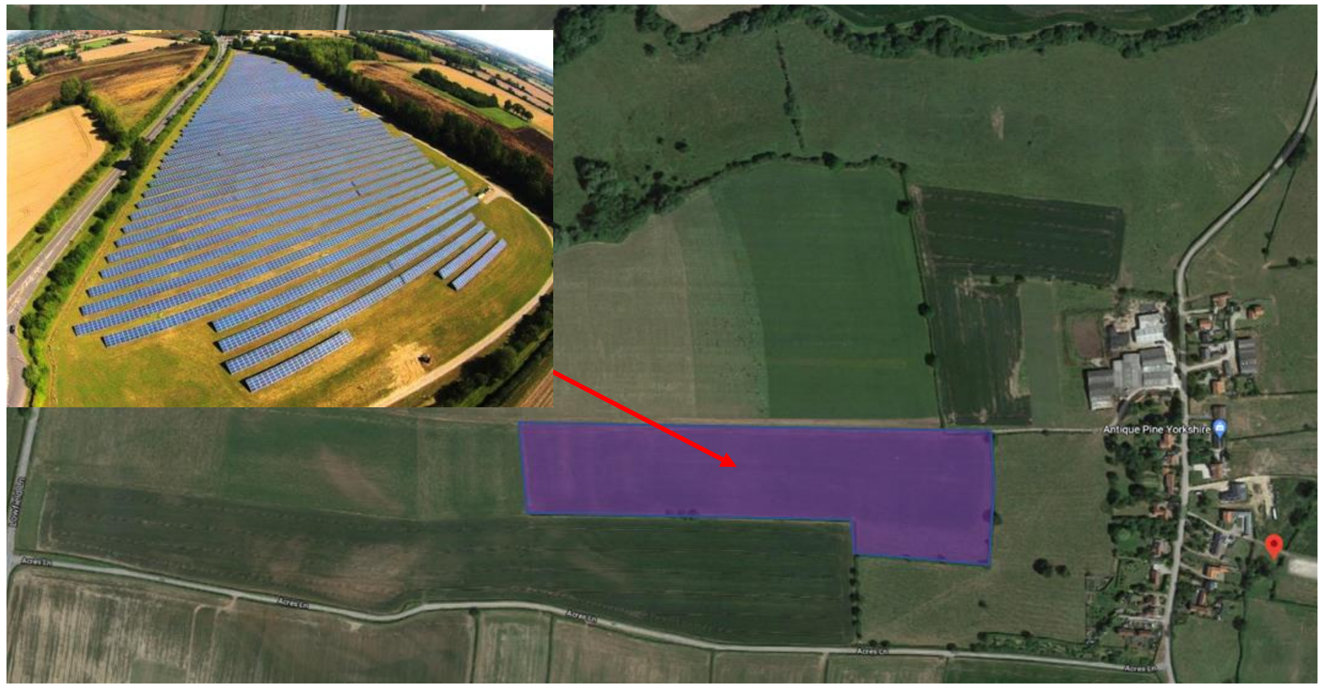

Figure 6—7 - Area Identified as Suitable for Solar PV

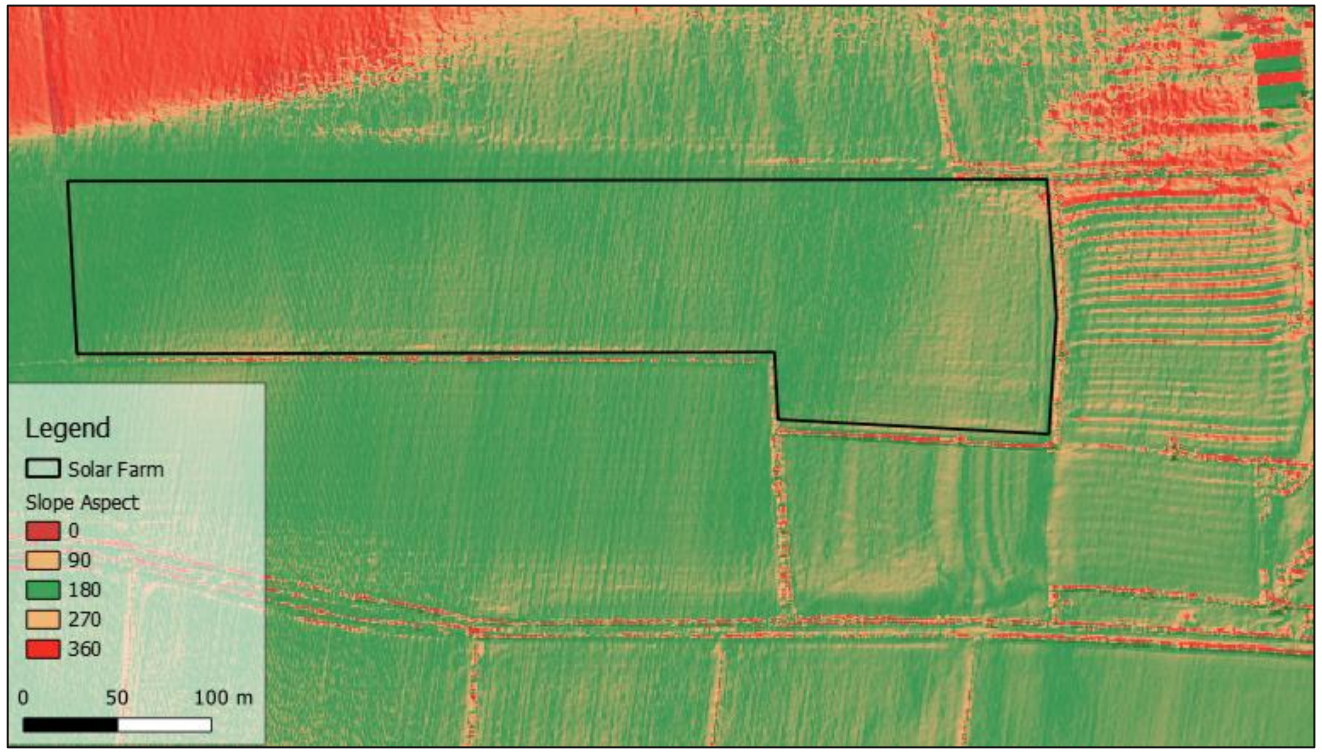

Figure 6—8 - Solar PV Slope Aspect -

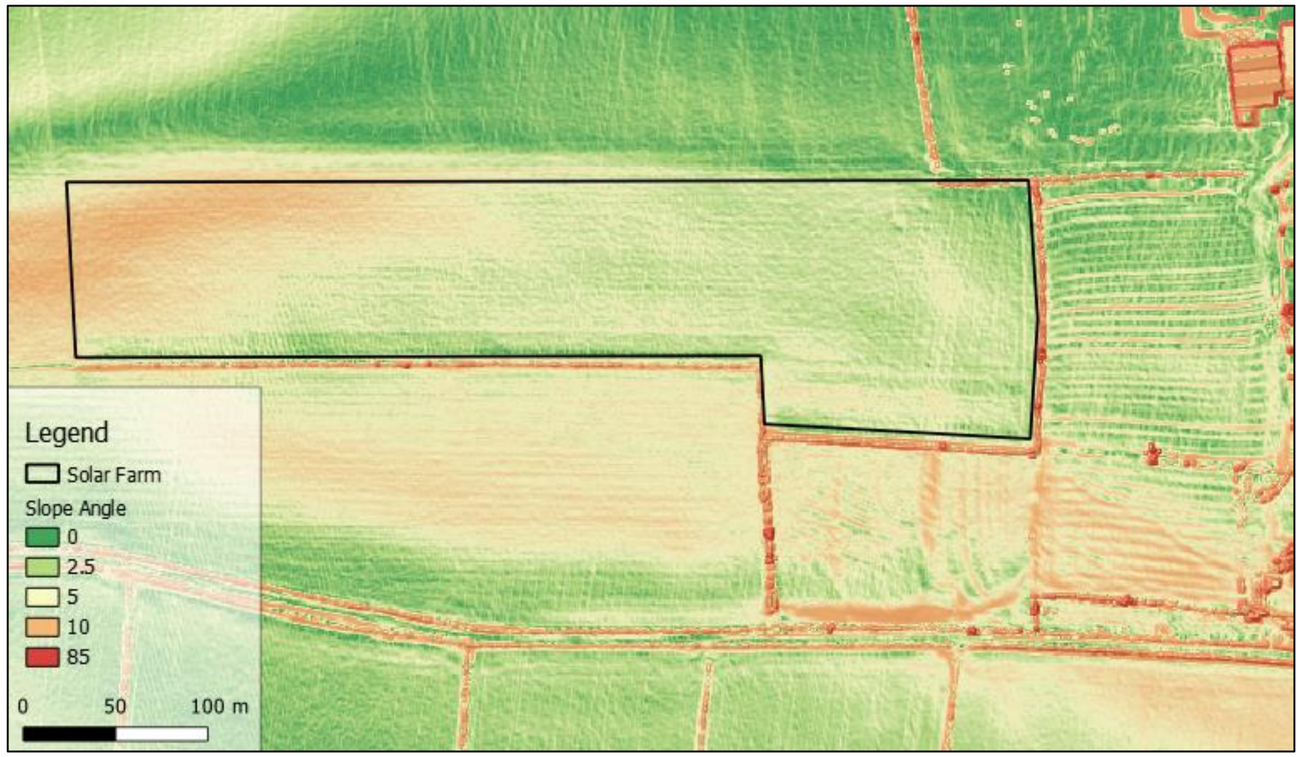

Figure 6—9 - Solar PV Slope Angle

6.10 Wind

As with Solar PV, wind power has been identified as having good potential within farm owned land areas. Wind also provides a complimentary profile to solar often generating at night and during winter months.

An area of land slightly to the north west of the farm has been identified as being suitable for deployment of wind turbines. The wind power rose for the turbine site indicates dominant wind speed and direction comes from the south to south west. The lack of obstructions in this direction is a positive for wind development.

For the purposes of the study a Nordex N27 150kW turbine has been considered which has a 37m hub height.

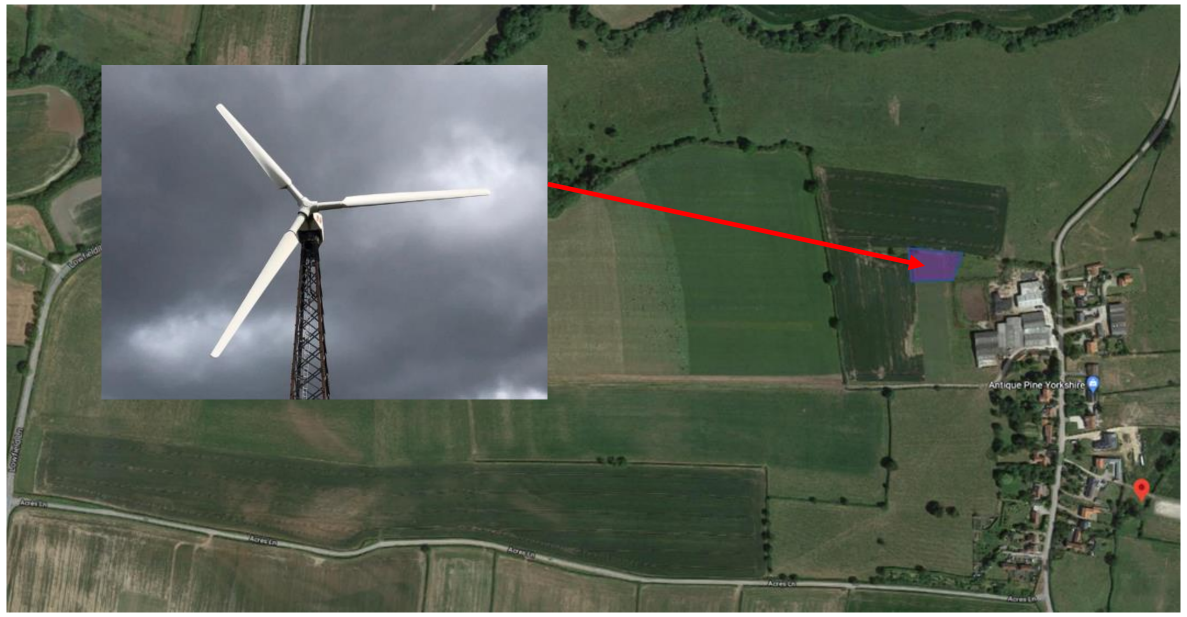

Figure 6—10 - Wind Turbine Location

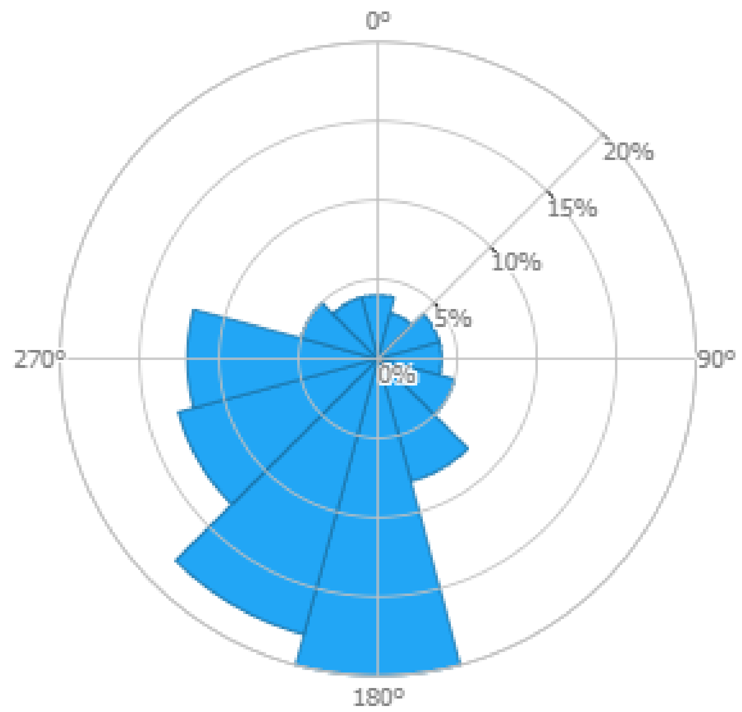

Figure 6—11 Rose Diagram

6.11 Joint Solar PV and Wind Solutions

For the scenarios discussed in section 7, joint wind and PV solutions have been considered which allow for a less intermittent supply of renewable power. The proposed areas are shown in Figure 6—12 with 2 potential locations for a wind turbine being considered.

Typical generation profiles for wind a solar PV are provided in Appendix B.

Figure 6—12 - Joint Solar PV and Wind Deployment

6.12 Batteries

Centralised battery storage has been considered in order to help balance periods of excess renewable generation with grid export limits or energy centre demands. However, following an assessment of battery CAPEX / OPEX costs vs. grid upgrade costs and the value add benefits of storage vs the CAPEX investment required it has been determined that this is not the best solution at this time unless NPG determine a power quality issue when considering the wider area strategy. The preference at this time based on the information received to date from NPG is that it is far more economic to pay for network reinforcement than to attempt to mitigate it with battery storage.

6.13 Grid Power

Village power is supplied by an existing pole mounted transformer rated at 82kW / 92 KVA.

Maintaining and reinforcing the existing grid power infrastructure has been deemed the most cost-effective way of providing and additional power demands, rather than providing new private power networks which could be fed from local renewables. This mitigates the overheads and risk associated with adopting the legacy equipment. This solution therefore determines the options for energy purchase; at this time a sleeved arrangement being seen to be the most preferable option.   However, the arrangement between the farm and the generation plant could potentially be via a private wire arrangement given that new infrastructure will be required in any case.

Should centralised heating and power solutions at the farm be deployed then a new substation of up to 1MVA at a cost of £300,000 to the SPV would be required. The existing power network serving the village would remain in its current state as no increases to power demands for the rest of the village are anticipated.

Should a decentralised ASHP approach be considered the upgrade of the existing pole mounted transformer should be undertaken through a join village application to the DNO. Upgrade to a 315KVA transformer would likely be required at a cost of ~£40,000 which would likely be bourne by the DNO. Upstream network reinforcement to not anticipated to be required.

7 Scenarios and Energy Modelling Results

7.1 Overview

Based on the outcome of the technology assessment, 6 scenarios were considered for energy modelling and techno-economic considerations. The scenarios can be summarised as follows:

- **Scenario A** – Decentralised ASHPs installed at building level
- **Scenario B** - Decentralised ASHPs installed at building level + Optimised renewables Installed at Farm
- **Scenario C** - Centralised ASHP + AD driven biogas CHP installed at farm serves village heat network. CHP serves energy centre demands with excess exported back to grid
- **Scenario D** - Centralised ASHP installed at farm serves village heat network. Optimised renewables at farm serve energy centre demands with excess power exported back to grid
- **Scenario E** - Centralised ASHP installed at farm serves village heat network. Large scale renewables at farm serve energy centre demands with excess power used to generate hydrogen or be exported back to grid
- **Scenario B+** - Considers deployment of large-scale renewables at the farm and supply of renewable power to nearby properties within villages which would transition to decentralised ASHP's (similar to Scenario A/B)

The following sections provide details of plant sizing and energy modelling results.

7.2 Scenario A

This scenario assumed 10 – 16kWth units installed at each property. With significant upgrade requirements to buildings to accommodate the ASHP plant.

Grid reinforcement would be required to upgrade the existing ~92kVa transformer to ~315kVa to meet the additional power demands of the village.

In order to meet individual property heat demands, as summarised in Table 5—2, the following additional power and grid capacity could be required as summarised in Table 7—1.

Table 7—1 Scenario A Energy Modelling Results

Option A – Dwelling level ASHP	Capacity Required	Annual Power (kWh)	Annual Thermal (kWh)
Resi and Farm Power Demands	83 kW (existing capacity)	157,032 (consumption)	830,108 (generated - provided predominantly through oil fired boilers)
Aggregated Heat Pump Demands	140 kWe (New additional required)	333,968 (consumption)	830,108 (generated)

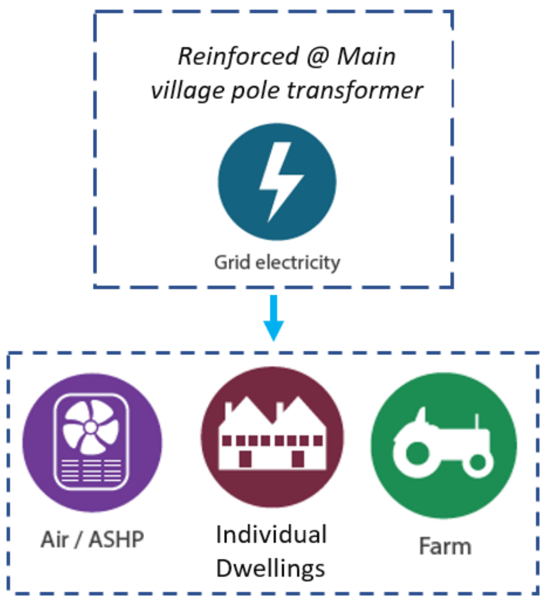

Figure 7—1 - Scenario A Configuration

7.3 Scenario B

This scenario assumes the same decentralised heat pump integrations at building level as outlined in scenario A, combined with 150kW of centralised Solar PV and a 150kW wind turbine installed at the farm, with generated power being sold back to the grid assuming 50% at national rates and 50% via a sleeved power arrangement to participants within the village (higher rate). Total village power supplied through PPA agreements from renewables located at the farm would equate to ~45% of annual demands, as summarised in Figure 7—3.

Reinforcement would be required at the farm to provide a connection up to 1MVA at a cost of ~£300,000 to an SPV if they were to deliver such a scheme.

Total village power demands would be as per Table 7—1.

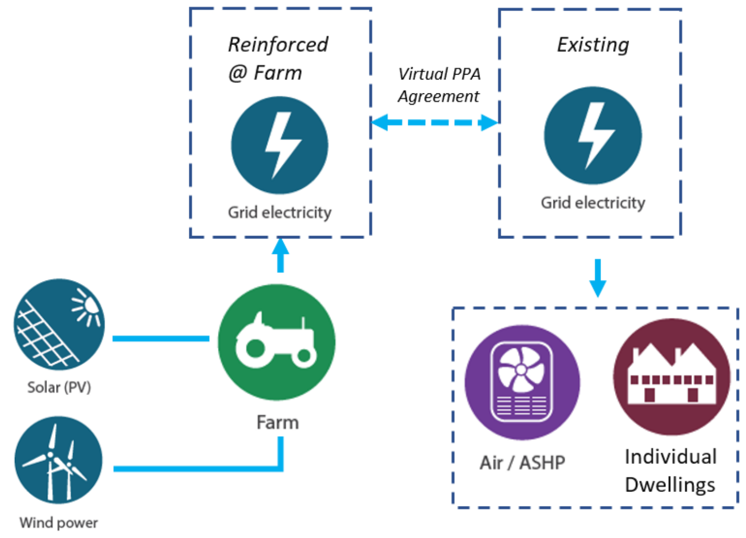

Figure 7—2 Scenario B Configuration

Table 7—2 Scenario B Energy Modelling Results

Option B – Private Wire Network	Capacity Required	Annual Power (kWh)	Annual Thermal (kWh)
Grid Power Import @ farm	~1 MVA	-	N/A
Grid Power Export @ farm	~1 MVA	445,834	N/A
Solar PV	150 kWp	145,450 (generated)	N/A
Wind	1 x 150kW (@37m hub height)	300,384 (generated)	N/A

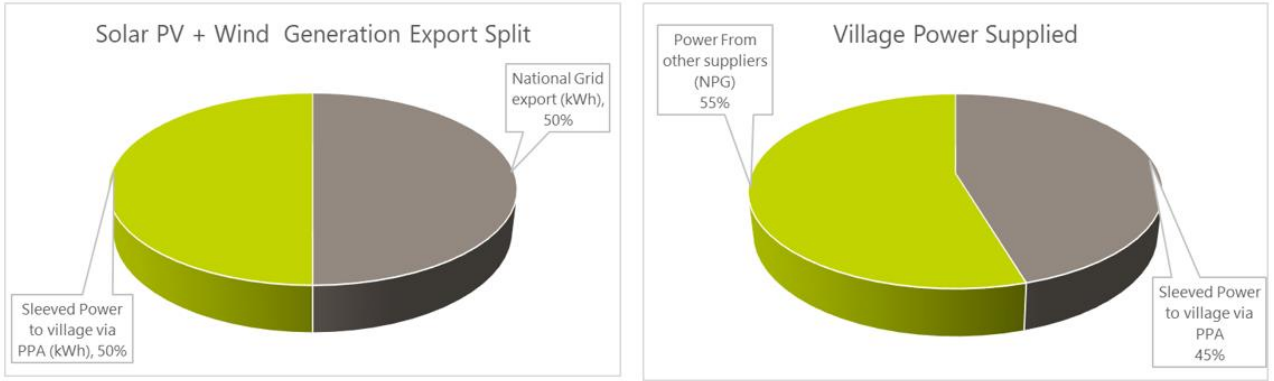

Figure 7—3 – Scenario B Modelled Power Splits

7.4 Scenario B+

A scenario B+ has been considered which includes full deployment of renewables within available land areas and supply of renewable power to nearby communities as outlined in section 4.2 via a virtual PPA agreement.

This scenario assumes the same decentralised heat pump integrations at building level as outlined in scenario A, are integrated across a further ~120 homes within nearby villages, 3,000kW of centralised Solar PV and a 150kW wind turbine installed at the farm in Leppington would provide power back to the grid assuming 100% is sold via a sleeved power arrangement to participants within Leppington and nearby communities .

Reinforcement would be required at the farm to provide a connection up to ~4MVA at a cost of ~£1.2m to an SPV if they were to deliver such a scheme. No power is anticipated for import for SPV owned plant at the farm.

Option B – Private Wire Network	Capacity Required	Annual Power (kWh)	Annual Thermal (kWh)
Grid Power Import @ farm	~1 MVA	-	N/A
Grid Power Export @ farm	~4 MVA	3,209,453	N/A
Solar PV	3000 kWp	2,909,069 (generation)	N/A
Wind	1 x 150kW (@37m hub height)	300,384 (generation)	N/A

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7.5 Scenario C

This scenario assumes a centralised heat network served from an energy centre located at the farm.

Anaerobic digestor plant would be installed in order to drive a ~30kWe CHP (sized based on annual calculated biogas yields from 160 dairy cows). CHP power would be used to meet energy centre demands with periods of excess generation exported back to grid.

~350kWth of centralised heat pumps would provide supplementary and backup heating demands when there is insufficient supply from the CHP.

The scenario assumes grid reinforcement of 1 MVA at farm and a sleeving arrangement with the DNO to virtually sell power back to participating villagers with any further excess power exported nationally, the modelling assumes 50% of exported power being sold back to the village and 50% nationally. Further breakdown on power splits in presented in Figure 7—5.

Blended flow temperatures of 75 – 85 degC would be supplied on the heat network. High grade heat from the CHP (90-95 degC) with 65 – 80 degC flow from heat pump would charge thermal stores with hydraulic blending taking place post storage.

Pending appropriate commercial arrangements with the farmer, the existing 100 kWth Biomass boiler could provide supplementary heat and act as backup for high grade heat source in absence of CHP.

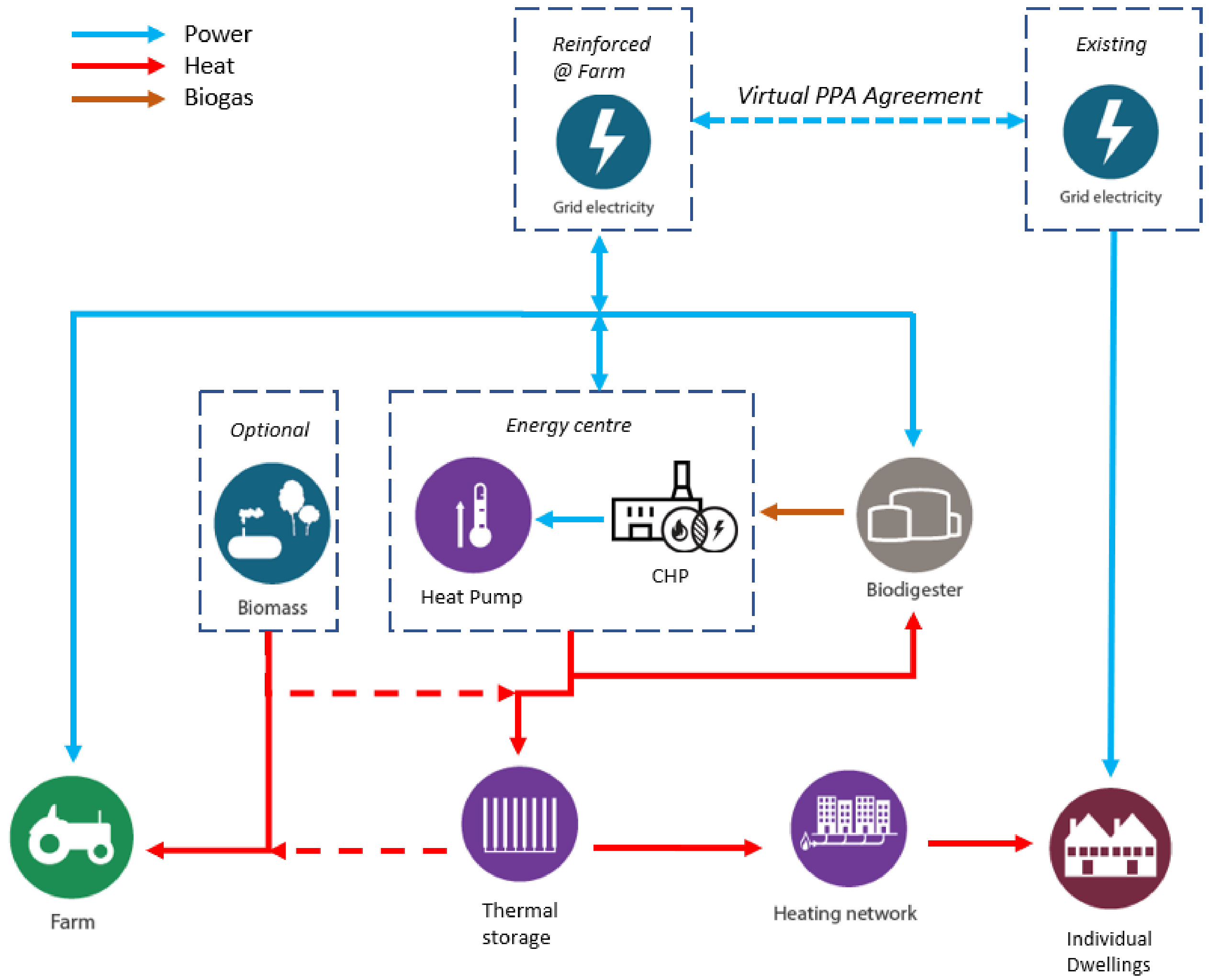


Figure 7—4 - Scenario C Configuration

Table 7—3 Scenario C Energy Modelling Results

	Capacity Required	Annual Power (kWh)	Annual Thermal (kWh)
Anaerobic Digestion	>200m3 storage volume ~77,760m3 / year generation	N/A	N/A
CHP	27/40 kWe/th	227,400 (generation)	331,100 (generation)
Biomass Boiler	100 kWth	-	13,100
Resi and Farm Demands	83 kW (existing power capacity)	157,032	830,108
EC Power Demands (ASHP + Ancillaries)	200 kW	269,720 (consumption)	N/A
Heat Pump	350 kWth (output) ~120kWe (input)	248,100 (consumption)	598,600 (generation)
Grid Power Export @ Farm	~1 MVA (CHP export)	40,300 (from CHP)	N/A
Grid Power import @ Farm	~1 MVA (When CHP cannot provide)	82,620	N/A
Thermal Store	20m3	-	-

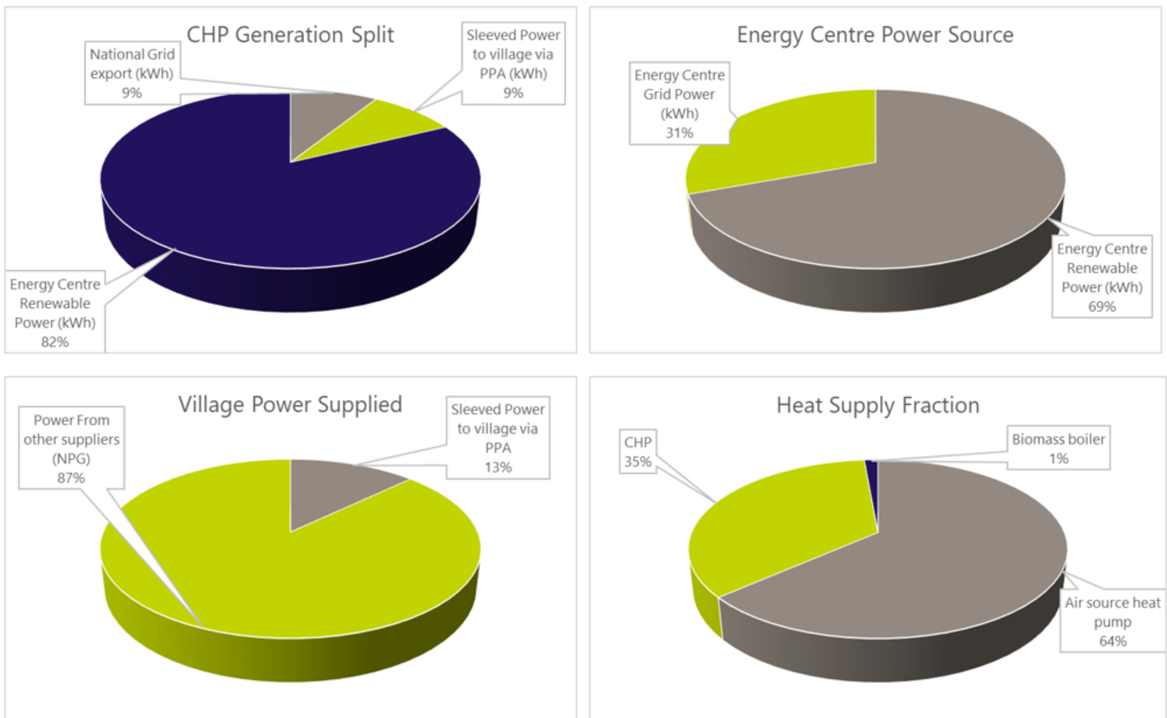


Figure 7—5 -Scenario C Modelled Power / Heating Splits

7.6 Scenario D

Scenario D assumes ~350kWth of centralised ASHP plant installed within an energy centre at the farm, serving a village wide heat network.

Optimally sized renewables (also located at the farm) would provide power for the energy centre with excess power being exported back to the grid. 50% of exported power is assumed to be used within the village via virtual PPA agreements while 50% is assumed to be exported nationally. Further breakdown on power splits in presented in Figure 7—7.

150kW of Solar PV and 1 no. 150kW wind turbine would be deployed in locations identified in illustrated in Figure 6—12 .

Grid reinforcement of up to 1 MVA would be required at the farm at a cost of ~£300,000 to the SPV.

Flow temperatures of the heat network would be lower than in scenario C of around 65 – 80 degC. Modifications to existing building level heating systems would likely be required to allow sufficient return temperatures on the network, however these are expected to be less invasive than if decentralised systems were to be installed (as is the case with scenarios A & B).

Pending appropriate commercial arrangements with the farmer, the existing biomass boiler could provide supplementary heat and act as backup for redundancy purposes.

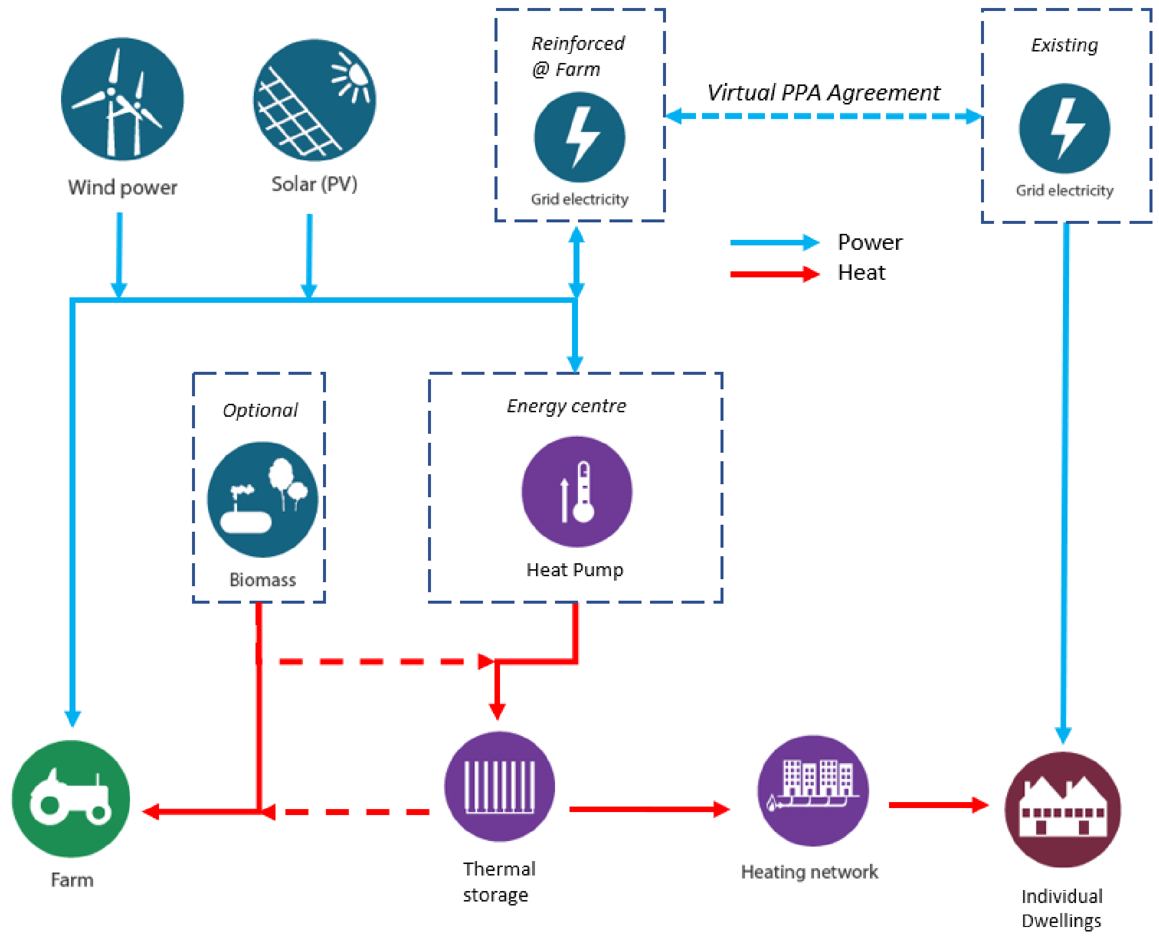


Figure 7—6 Scenario D Configuration

Table 7—4 - Scenario D Energy Modelling Results

	Capacity Required	Annual Power (kWh)	Annual Thermal (kWh)
Anaerobic Digestion	>200m3 storage volume ~77,760m3 / year generation	N/A	N/A
CHP	27/40 kWe/th	227,400 (generation)	331,100 (generation)
Biomass Boiler	100 kWth	-	13,100
Resi and Farm Demands	83 kW (existing power capacity)	157,032	830,108
EC Power Demands (ASHP + Ancillaries)	200 kW	269,720 (consumption)	N/A
Heat Pump	350 kWth (output) ~120kWe (input)	248,100 (consumption)	598,600 (generation)
Grid Power Export @ Farm	~1 MVA (CHP export)	40,300 (from CHP)	N/A
Grid Power import @ Farm	~1 MVA (When CHP cannot provide)	82,620	N/A
Thermal Store	20m3	-	-

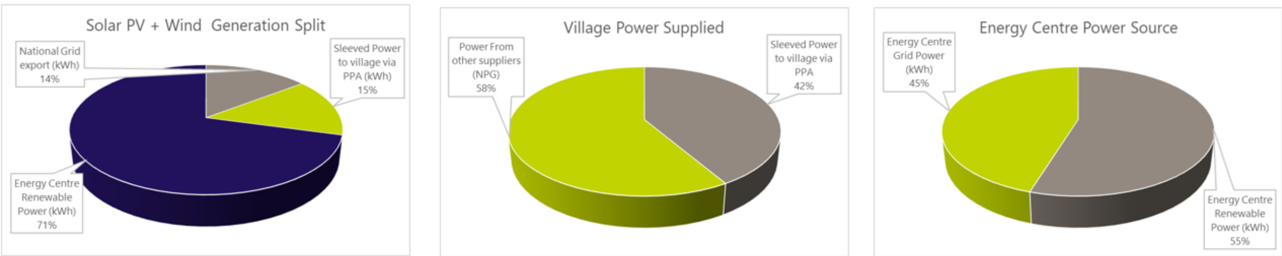


Figure 7—7 - Scenario D Modelled Power Splits

7.7 Scenario E

Scenario D assumes ~350kWth of centralised ASHP plant installed at the farm serving a village wide heat network, as described within scenario D.

Large scale renewables installed at the farm would provide power for the energy centre with excess power being used to generate hydrogen or be exported back to the grid. 50% of exported power is assumed to be used within the village via virtual PPA agreements while 50% is assumed to be exported nationally. Further breakdown on power splits in presented in Figure 7—9.

Based on the identified land available at the farm, 3MW of Solar PV and 1 no. 150kW wind turbine could potentially be deployed as illustrated in Figure 6—12.

2 no. 700kWe HGAS1SP electrolyser units could be deployed to utilise excess renewable generation for hydrogen production.

Grid reinforcement of ~1 MVA would be required at the farm at a cost of ~£300,000 to the SPV.

Flow temperatures of the heat network would be as described within scenario D.

Pending commercial agreement, the existing biomass boiler could provide supplementary heat and act as backup for redundancy purposes.

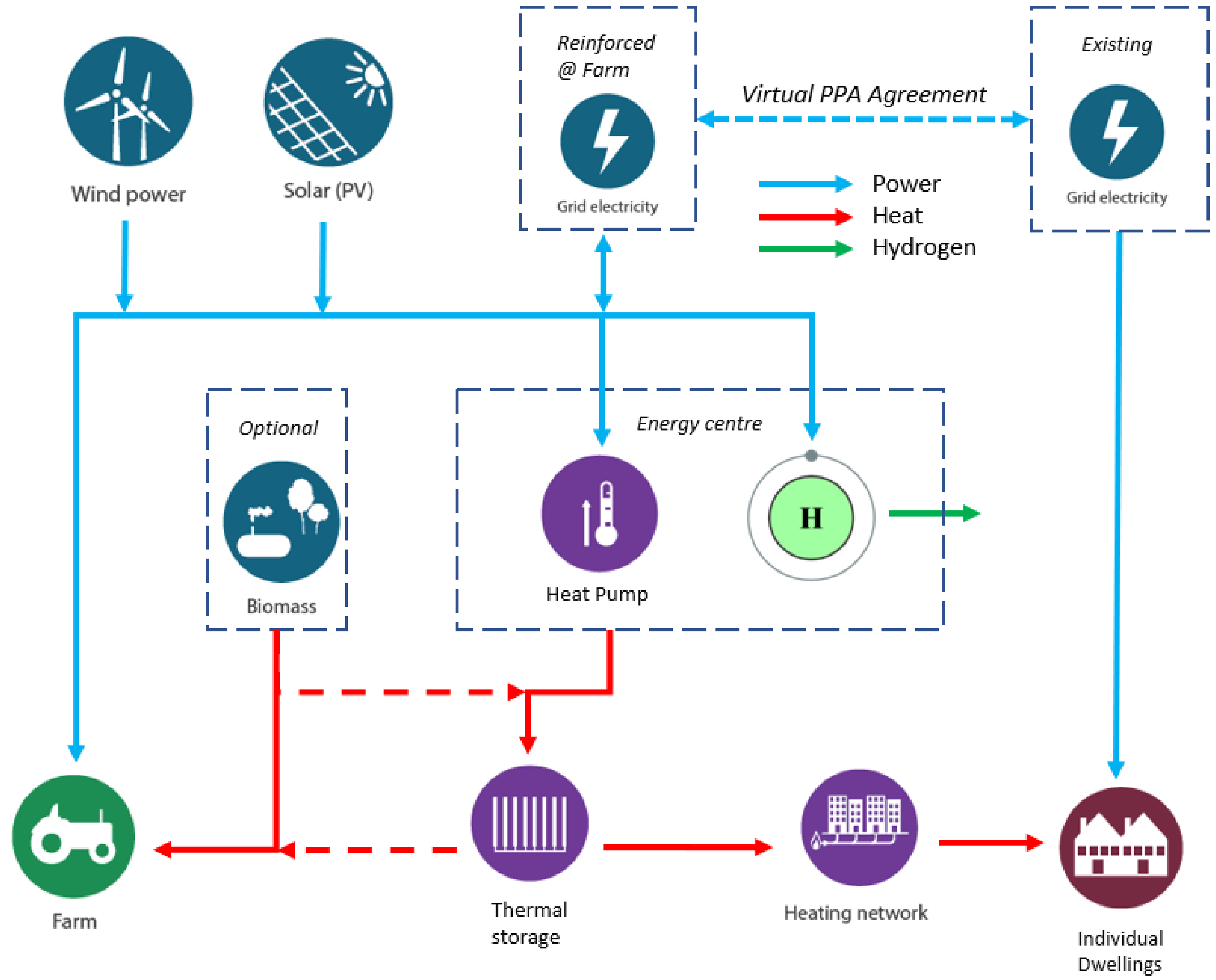


Figure 7—8 - Scenario E Configuration

Table 7—5 - Scenario E Energy Modelling Results

	Capacity Required	Annual Power (kWh)	Annual Thermal (kWh)
Biomass Boiler	100 kWth	Not considered under normal operation	Not considered under normal operation
Resi and Farm Power Demands	83 kW (existing capacity)	157,032 (consumption)	N/A
EC Power Demands (ASHP + Ancillaries)	200 kW	418,643 (consumption)	N/A
Heat Pump	350 kWth (output) ~120kWe (input)	380,584 (consumption)	945,170 (generation)
Grid Power Export @ Farm	~1 MVA	1,140,054	N/A
Grid Power import @ Farm	~1 MVA	37,644	N/A
Thermal Store	20m3	N/A	N/A
Solar PV	3000 kWp	2,909,069 (generation)	N/A
Wind	1 x 150kW (@37m hub height)	300,384 (generation)	N/A
Hydrogen Generation	2 x 700kW units	26,532 kg	N/A
Hydrogen Power Demand	1400 kW	1,688,400	N/A

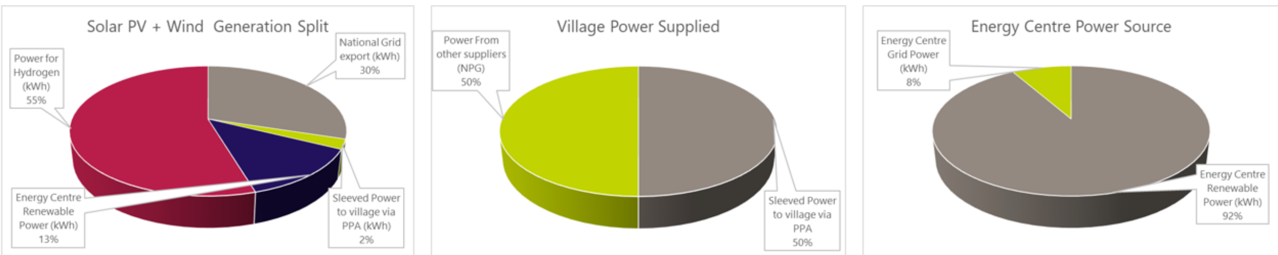


Figure 7—9 - Scenario E Modelled Power Splits

8 Commercial Considerations & Financial Projections

8.1 Techno Economic Modelling

A techno-economic cashflow model (TEM) has been built to assess the possible return on investment each scenario can achieve over a 40-year time period from the perspective of a Special Purpose Vehicle (SPV).

The benefits to the individual households are represented as the annual cost of energy (heat and power) compared to the Business as Usual (BAU) (the 'counterfactual').

The five options (A-E) have been assessed against receiving the Renewable Heat Incentive (RHI) as a possible funding stream.

8.1.1 Methodology

A techno-economic cash flow model (TEM) was built in MS Excel combining the technical details of the scheme (capital and operational) with appropriate cost/price inputs to generate an annual cash flow. This enabled an assessment of viability (pre-tax) using Net Present Value (NPV) and Internal Rate of Return (IRR) as key indicators.

The key assumptions include:

- The SPV generates heat and power. The energy is sold via a number of options to the grid or individual households, as detailed in Section 8.1.2.
- The SPV owns and operates the heat network up to an including the HIUs at each building connection
- Heat is sold to each household at a non-bulk variable rate and standing charge
- 15% heat network losses
- 4% parasitic electrical pumping power as a percentage of network heat load. 2% of which is attributed to distribution pumping (as per CP1). The remaining 2% is attributed to other pumping and controls at the energy centre
- Options A and B: no heat network - households install and operate their own individual ASHPs
- All households are connected in one phase, (assumed 2025)
- The farmer is paid for lease of the land (PV and wind farms) at a rate of £1,500 per acre

8.1.2 Modelling Assumptions

SPV power sales

Power generated at the farm is split into the following uses depending on the option:

- **Energy Centre:** power used on the farm to run the energy centre (heat pump, controls, pumping etc.) – no sales price
- **Hydrogen:** power used on the farm to produce hydrogen – no sales price
- **Virtual PPA:** power sold to households via a virtual power purchase agreement – 9p/kWh
- **Grid export:** the remaining power is sold back to the grid – 5.5p/kWh

Household heat and power sales

The assumed heat prices for residential bulk connections are shown in Table 8—1, split into standing charge and variable rate. The rates are based on an average of several Heat Trust registered operational projects and quotes for schemes in London obtained by BuroHappold.

- The standing charge is a flat rate paid to the DHN operator for connection to the network. For heat network pricings, this is usually based on the avoided costs of connecting into the DHN compared to the counterfactual of gas boilers.
- The variable rate is the price paid per unit of heat consumed by each customer – again usually based on the fuel cost to deliver a kWh of heat compared to the counterfactual. E.g. cost of gas per kWh divided by the boiler efficiency.

The heat price at this stage is indicative and subject to change. There is currently no regulatory body for the supply of heat from DHNs however the heat pricing strategy will need to comply with the Heat Network (Metering and Billing) Regulations 2014[1]. All schemes BuroHappold have based the heat price are based on are Heat Trust compliant[2] - in-lieu of official regulation for heat networks the Heat Trust is a not for profit company focussed on customer protection for the district heating sector.

Table 8—1 Heat price – variable and standing charge

	Variable rate (p/kWh)	Standing charge
Residential	5.6	£328/yr per household
Commercial	5.6	£24/kW

Households import electricity either direct from the grid of through virtual PPA. The virtual PPA rate is set to be lower than the grid import, giving savings to the resident compared to the gird import alternative. Prices are detailed in Table 8—2.

Table 8—2 Power prices – grid and PPA

	Variable rate (p/kWh)
Grid import	12.0 p/kWh
PPA	11.0 p/kWh

SPV hydrogen sales

A hydrogen sales price is set as a key input into the model (Table 8—3). As the hydrogen market is not yet fully established, there is limited information on the price that the SPV would likely receive for the generated hydrogen.

Table 8—3 Hydrogen sales

	Hydrogen sales
Hydrogen sales price	£3.1/kg

[1] http://www.legislation.gov.uk/uksi/2014/3120/pdfs/uksi_20143120_en.pdf

[2] Heat Trust, 2018. *Heat Cost Calculator: Further information and background assumptions*. Available at: <http://www.heattrust.org/images/docs/HCC_Further_information_and_assumptions_Jan2019_update__v1.pdf>

8.1.3 Modelling Boundaries

The modelling boundaries, including the revenue and expenditure streams are illustrated in the following section. The CAPEX and OPEX items associated with each option are summarised in appendix C

Scenario A

Individual dwellings install and operate their own ASHPs. There is no SPV involvement.

Significant retrofit costs on buildings to accommodate lower temperature heating plant of 10 – 16 kWth ASHP units required per dwelling. Grid reinforcement costs likely required to accommodate this option. A collective application to DNO for reinforcement up to 315 kVa (~£40k) required for backup supply and to allow power export, presenting a cheaper alternative to battery storage.

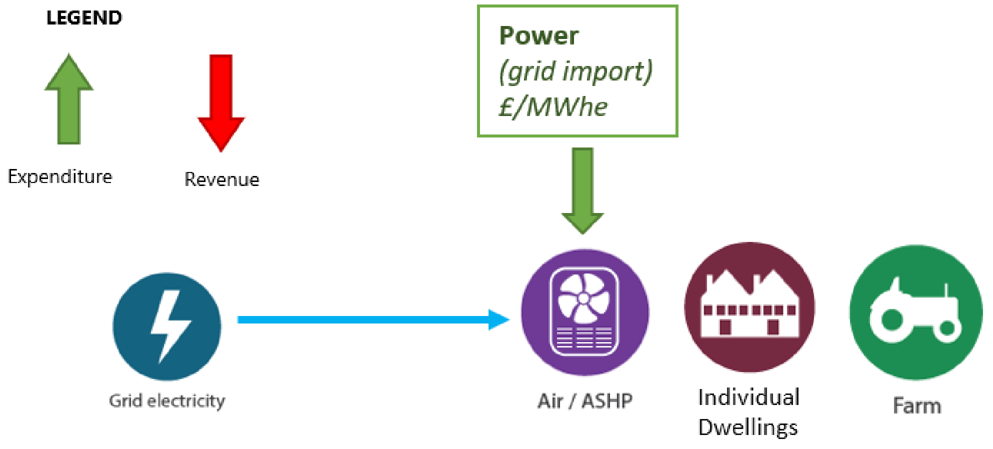


Figure 8—1 Scenario A modelling boundary

Scenario B / B+

Renewables installed at the farm, with a portion of power sold to the village via virtual PPA.

Option B assumes grid reinforcement of up to 1 MVA at farm, virtual PPA arrangement with DNO to virtually sell renewable power back to village.

With scenario B+ the renewable generation capacity increases to maximise the land availability and provide low carbon power to a number of nearby villages via virtual PPA's.

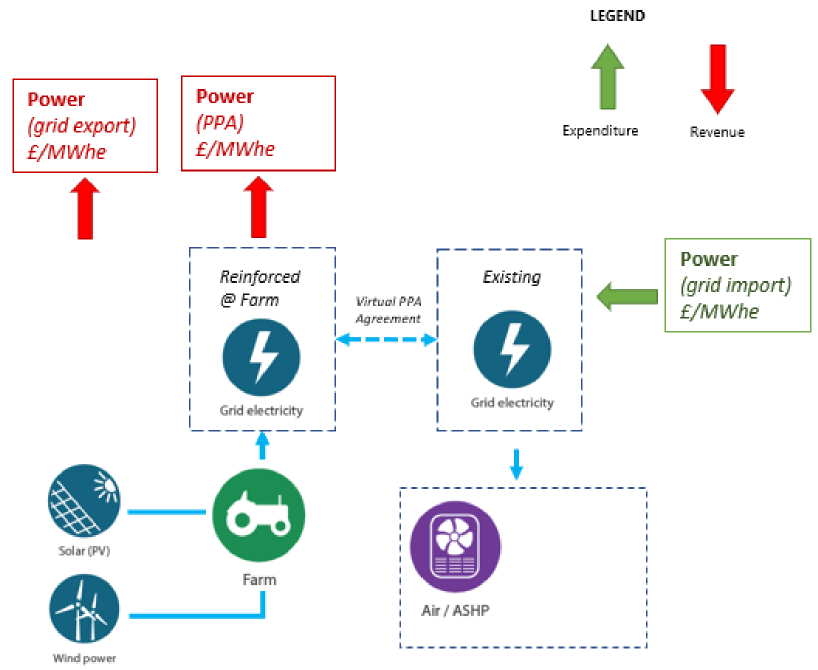


Figure 8—2 - Scenario B modelling boundary

Scenario C

Centralised plant at farm provides heat to village via heat network and PPA agreement for excess CHP power. Biomass boiler provides supplementary heat and act as backup for high grade heat source.

Assumes grid reinforcement of 1 MVA at farm, sleeving arrangement with DNO to virtually sell power back to village and any further excess power nationally. Blended flow temperatures of 75 – 85 degC on heat network.

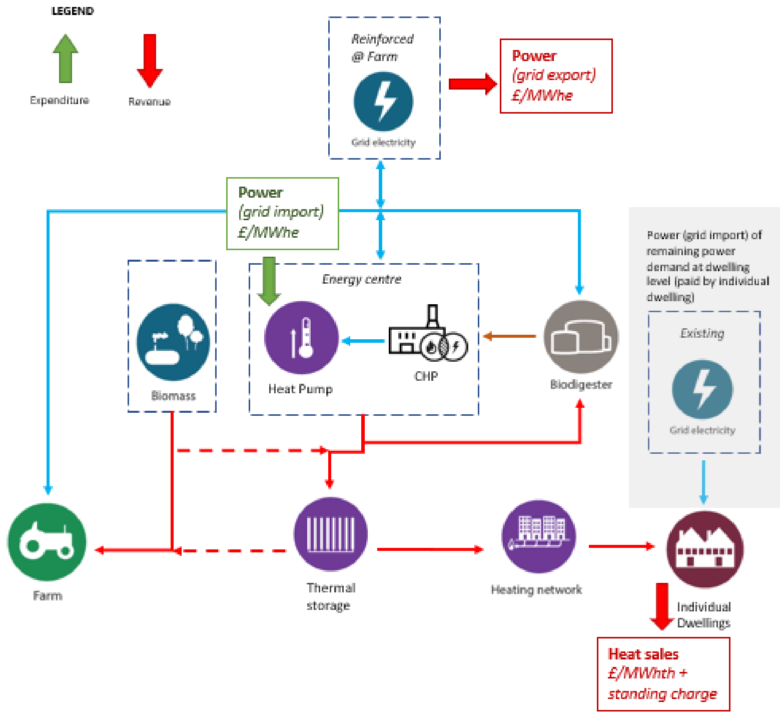


Figure 8—3 Scenario C modelling boundary

Scenario D

Centralised plant at farm provides heat to village via heat network and optimised renewable power with PPA agreement. Assumes grid reinforcement of 1 MVA at farm, sleeving arrangement with DNO to virtually sell power back to village and any further excess power nationally.

Flow temperatures of 65 – 80 degC on heat network. Low return temperatures <60 degC required to allow proper functionality – more significant secondary modifications within dwellings likely required.

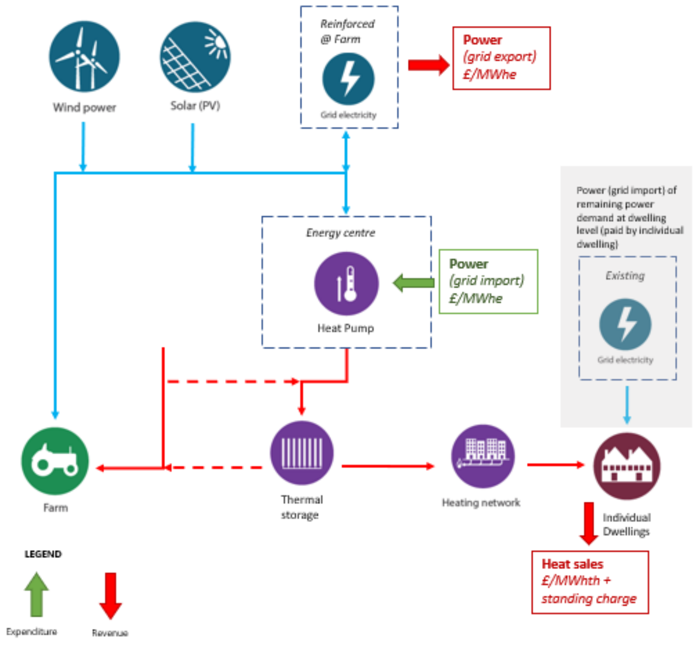


Figure 8—4 Scenario D modelling boundary

Scenario E

Centralised plant at farm provides heat to village via heat network and large-scale renewable power with hydrogen production and PPA agreement.

Assumes grid reinforcement of 1 MVA at farm, sleeving arrangement with DNO to virtually sell power back to village and excess power generation nationally when no requirement for hydrogen. 2 no. ITM HGas1SP electrolysers assumed with 700kW power input, 11 kg/h of hydrogen output each.

Flow temperatures of 65 – 80 degC on heat network. Low return temperatures <60 degC required to allow proper functionality – more significant secondary modifications within dwellings likely required

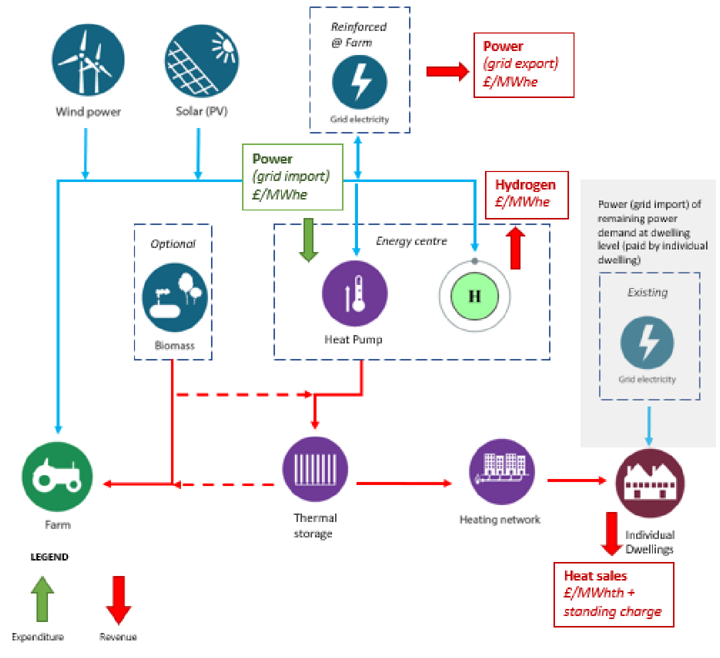


Figure 8—5 Scenario E modelling boundary

8.1.4 Modelling Inputs

A full breakdown of the capital (CAPEX) and operational (OPEX) costs can be found in Appendix C.

8.1.4.1 CAPEX

Industry quotes have been obtained for key plant including heat pump units, boiler, thermal stores, package substations at buildings and network pumps. Network costs have been determined using linear metre costs. Costs to each party are summarised in Figure 8—6.

20% contingency has been applied to all cost estimates, with an additional 5% for installation and delivery and 16% for prelims, design fees, testing and commissioning applied where not included in manufacturer quotes. The costs are subject change and future site investigation is recommended.

The modelling assumes that the DNO will cover the cost for grid reinforcement for decentralised heat pump scenarios (A & B/B+)

Connection charge

A connection charge of £3,500 per household is applied in Options C – E to account for the avoided cost of replacing the counterfactual oil boilers.

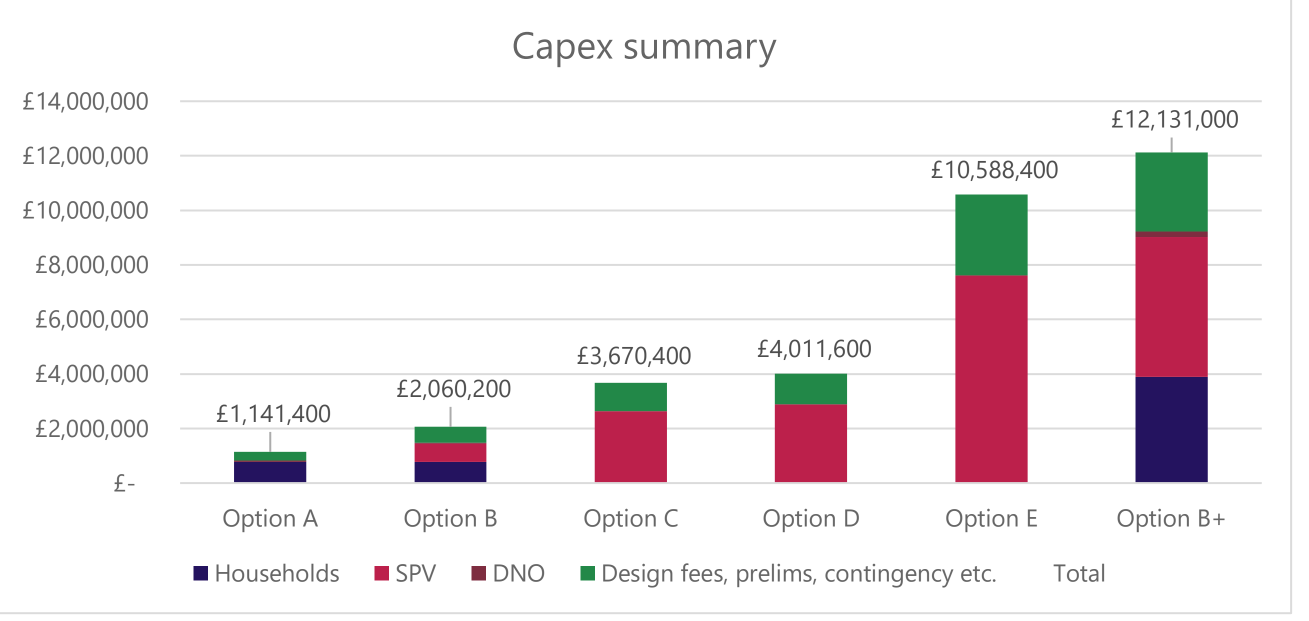


Figure 8—6 Capital cost summary

8.1.4.2 OPEX

Table 8—4 presents the commercial assumptions made regarding the operation of the scheme. OPEX costs have been included in the model based on a number of manufacturer quotes and other references.

For the purposes of this study, a discount rate of 3.5% has been applied to pre-debt cash flows.

Table 8—4 Opex assumptions

	Value	Unit
Wind and solar farm	1.50	p/kWh
Biodigester	2%	% of CAPEX
Heat pump	4%	% of CAPEX
CHP	4%	% of CAPEX
Farmland rental	£1,500	£/acre/pa
Plate heat exchanger	0.80	p/kWh
District network	0.06	p/kWh
HIUs	£37	£ per unit
Heat meters	£25	£ per unit
Metering and billing – bulk	£500	£ per connection
Metering and billing – non-bulk	£25	£ / unit
Staff costs	20,000	£ / yr
Replacement cost sinking fund for heat network	80%	% of heat network capex
Counterfactual fuel charges		
Burning oil	4.7	p/kWh

8.1.5 Results

The results for each option are presented in the following section from the perspective of both the SPV and the individual households.

8.1.5.1 SPV cashflow

Figure 8—8 and Figure 8—9 show the 40-year cashflows of each option. From these graphs it is clear that none of the scenarios make a return on investment without significant funding streams or low interest loans to cover the initial capital cost. Options B and E both have positive cashflows of approximately £6.6k / annum per year, suggesting they could attract investment from a third-party SPV.

Outputs from Scenario B+ plus suggest a positive cashflow of approximately £190k / annum, suggesting a potentially attractive prospect for a third party SPV to invest.

The modelling suggests Options C and D will both have negative annual cashflows. With expenditure on operation, maintenance and replacement costs outstripping the possible heat and power sales these options are unlikely to attract third party investment.

Figure 8—7 shows the breakdown of the annual cashflows as expenditure and revenues for the SPV. Although both Options B and E both have similar annual net cashflows, Option E incorporates the much larger annual spending required to operate the hydrogen electrolysis, as well as the heat network operation.

In Option B, the SPV is generating and selling renewable power, with no heat sales. The grid export price (estimated at a relatively optimistic 5.5p/kWh) is unlikely to be sufficient to offset the operation and maintenance requirements of the wind and solar farm. As can been seen in Figure 8—7, the revenue stream of this option is heavily dependent on the portion of that heat which can instead be sold via virtual PPA to the village's households (sold at the increased rate of 9.0p/kWh). If a virtual PPA agreement can be extended to 100% of the renewable power generation, the SPV's net cashflow will further increase, making Option B more attractive to third party investment.

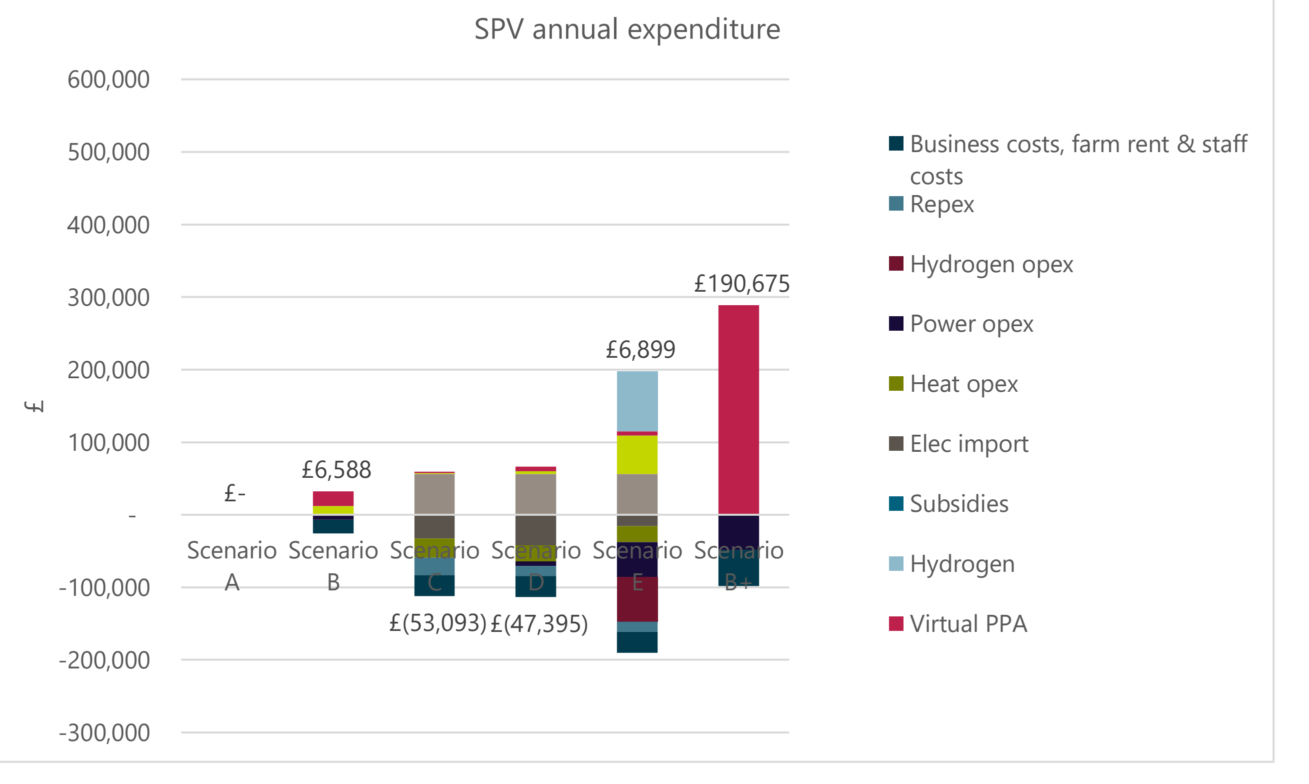


Figure 8—7 SPV annual expenditure

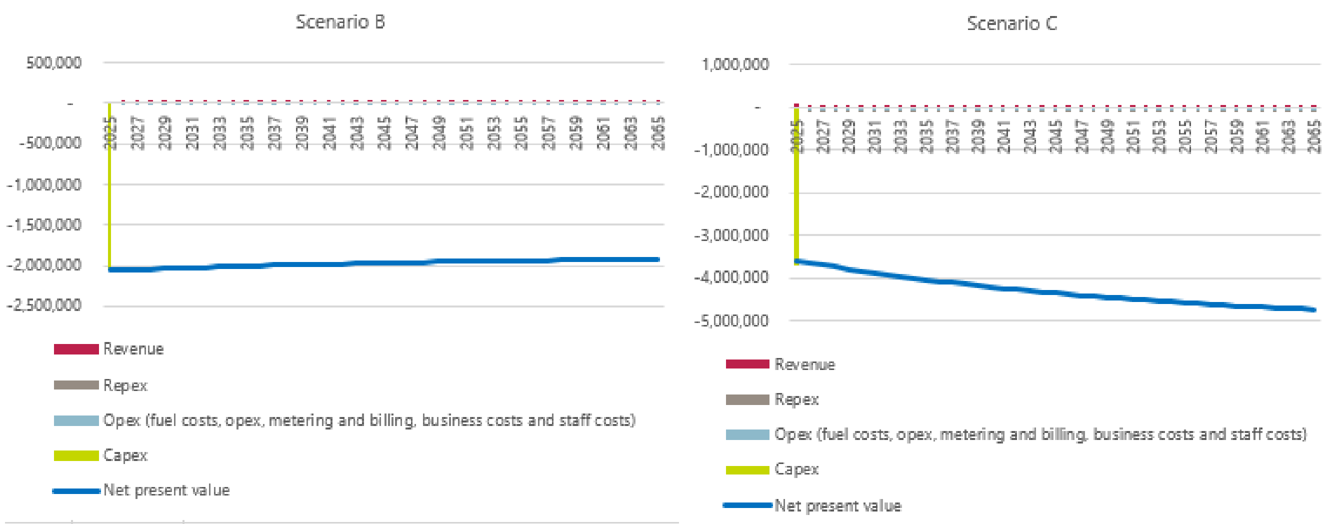


Figure 8—8 Option B and C cashflows

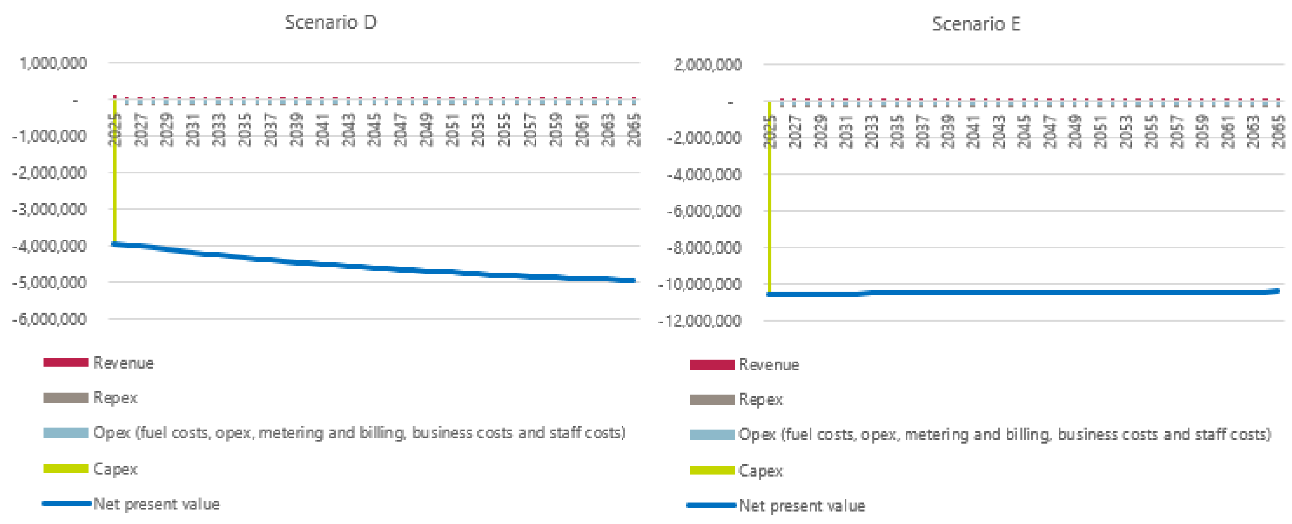


Figure 8—9 Option D and E cashflows

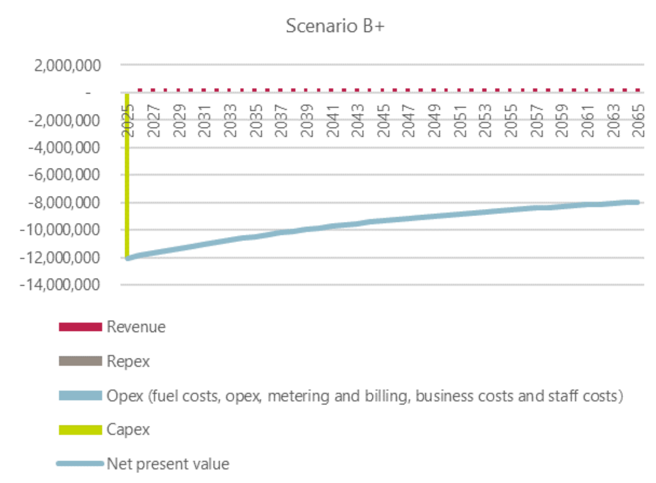


Figure 8—10 Option B+ cashflow

8.1.5.2 Household expenditure

The annual average household expenditure on energy (power and heat) for each option is compared to the counterfactual of gas boilers and 100% grid import in Figure 8—11.

The modelling suggests Options A and B would provide a saving to the household of approximately £280-190 each year. Whereas connection to the heat network (Options C, D and E) would increase annual expenditure by approximately £340 each year.

This analysis is based on the current oil import price of 4.7p/kWh. However, oil prices are extremely vulnerable to price fluctuations, with BEIS projecting that oil prices could increase by up to 20% by 2035. Connecting to a heat network or electrifying heat supply protects households against these price increases which will have a significant impact on residents, particular those in fuel poverty.

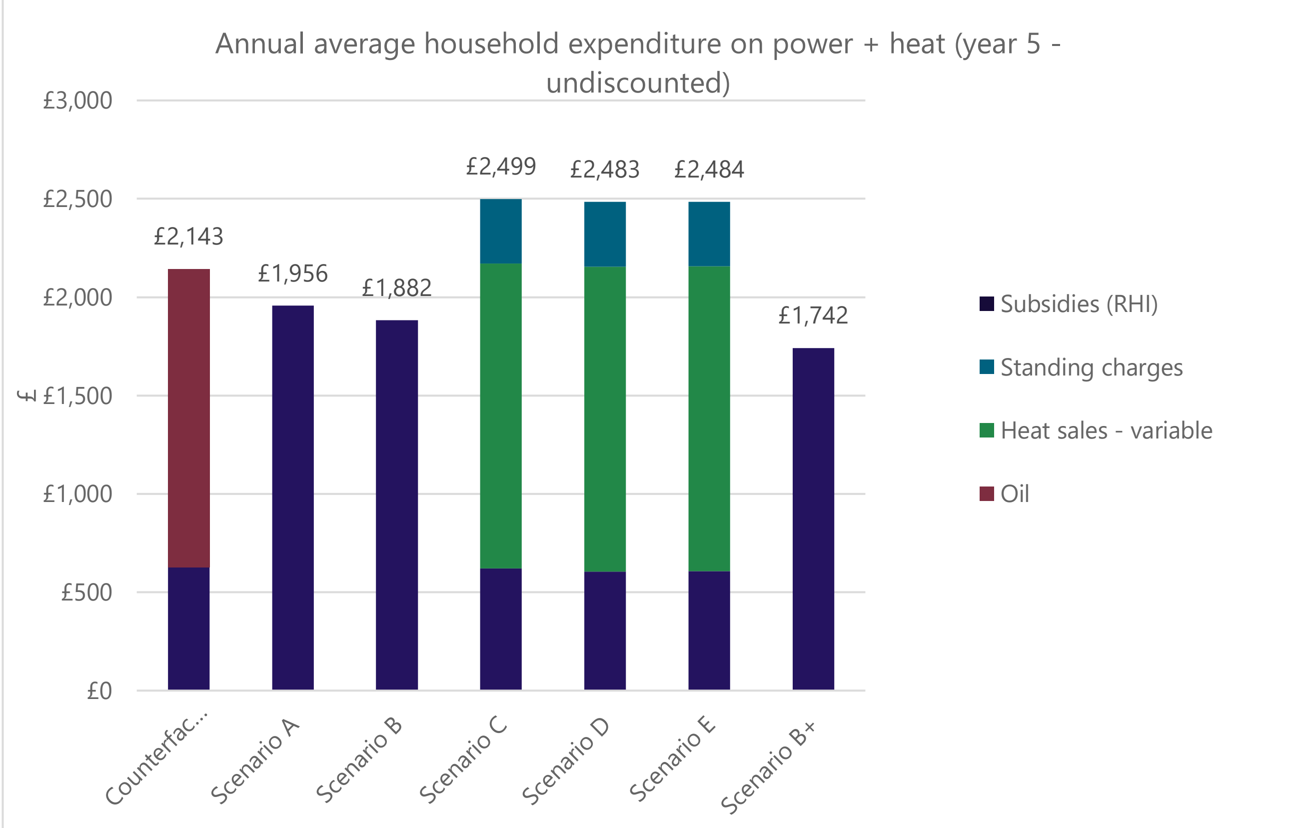


Figure 8—11 Annual average household expenditure on power & heat

Household capital costs

Initial analysis suggests the running costs of Option A and B are lower than the counterfactual. Table 8—5 illustrates the possible cost to households by installing an ASHP and carrying out the required retrofit measures (such as double glazing, cavity wall insulation and new heat emitters).

Capital cost per household (Option A & B)	
ASHP	£6,000
Retrofit (worse case)	£20,000
Green Homes Grant	- £5,000
TOTAL	**£21,000**

Table 8—5 estimated capital cost per household

The Green Homes Grant

A portion of the CAPEX can be covered by the Green Homes Grant:

- The government will provide a voucher worth up to £5,000 (or £10,000 to eligible low-income households) to help cover the cost of making energy efficient improvements to your home
- Improvements could include insulating your home to reduce your energy use or installing low-carbon heating
- You must redeem the voucher and ensure improvements are completed by 31 March 2021

8.1.6 Sensitivity

A sensitivity around receiving The Renewable Heat Incentive (RHI) payment was assessed. The results are presented below.

The RHI is a government subsidy paid per unit of renewable heat generated. For air source heat pumps the rates are currently:

- Domestic RHI applications (Options A & B), payments are received for 7 years at a rate of 10.85p/kWh.
- Non-Domestic RHI applications (Options C, D & E), payments are received for 20 years at a rate of 2.79p/kWh.

The RHI scheme is currently closing:

- Non-domestic - stage 2 applications must be completed by 31st March 2021 with funding in place
- Installations must be commissioned by 31st March 2022
- Domestic – applicants should have eligible systems commissioned and delivering heat by 31st March 2022

Consultations are underway for a replacement scheme:

- Non-Domestic – government has pledged £270m for a Green Heat Network Scheme
- Domestic – grants of ~4k / installation to be made available
- Expected to be clarity on scheme replacement over coming months

8.1.6.1 SPV cashflow with RHI

Under the current non-domestic RHI rates, the SPV could be eligible to receive approximately £23k of additional revenue for the first 20 years of operation. This increases Option E's annual cashflow from £6.6k to £30k (Figure 8—12).

As the RHI is paid to the body producing renewable heat, it does not affect the cash flow of Options A and B, where the households produce their own heat.

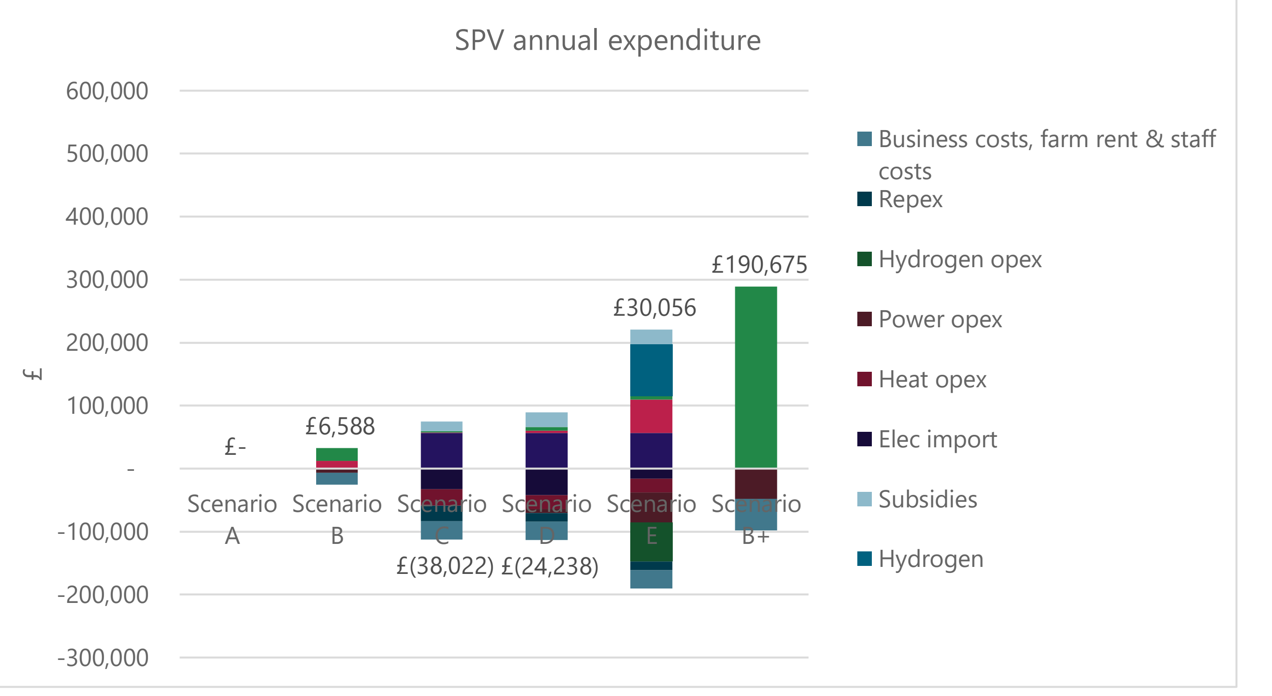


Figure 8—12 SPV annual expenditure – with RHI

8.1.6.2 Household expenditure with RHI

Using the current domestic RHI rate, the average household could be eligible to up to £1.8k revenue for the first seven years of heat pump operation in Option A, B and B+ (Figure 8—13). In these initial years, this would reduce annual expenditure by 90% compared to the counterfactual.

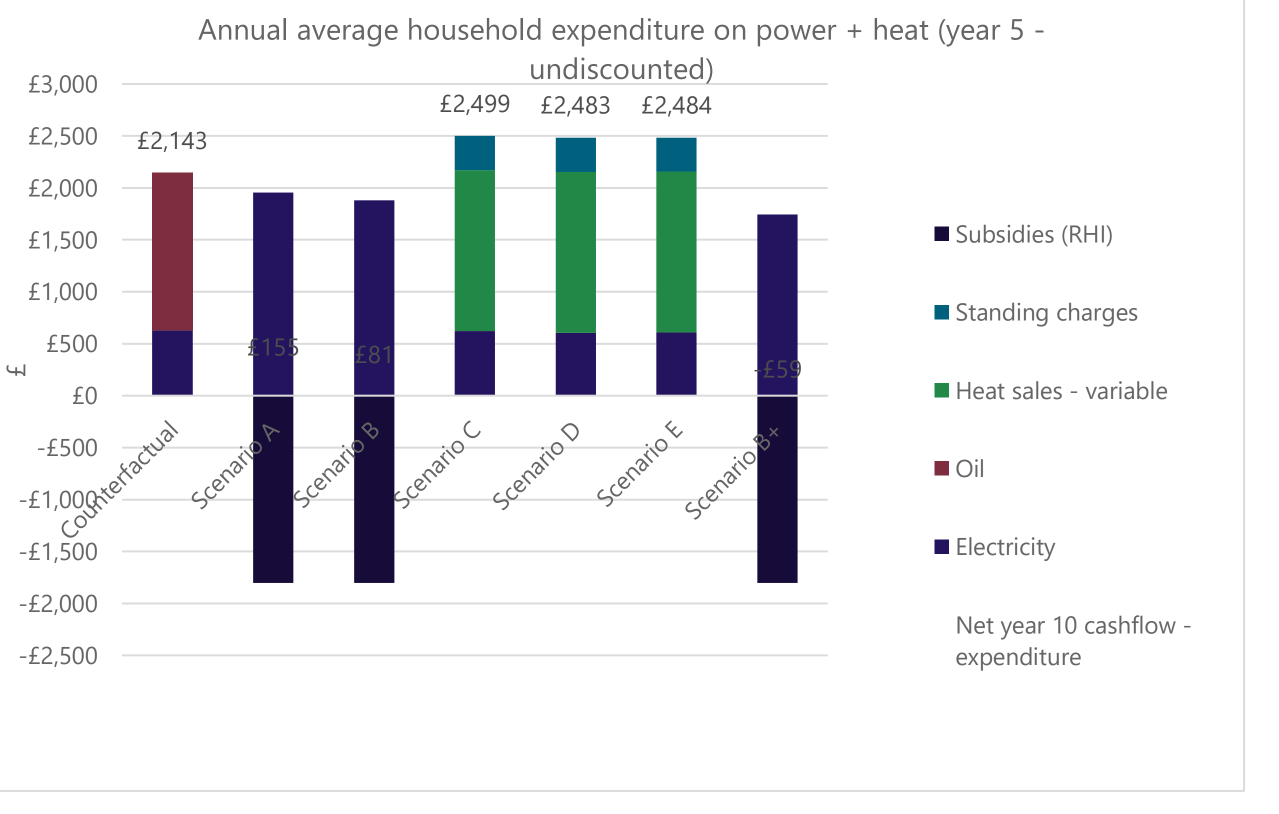


Figure 8—13 Annual average household expenditure on power & heat – with RHI

8.1.7 Commercial structures

A range of commercial structures both current and emerging are possible in evaluating the potential of the scheme. For the purposes of the analysis a PPA arrangement has been assumed between an established energy supplier and the community energy owned generator based on a fixed price agreement. The energy supplier is assumed to procure all energy from the generator and supply this to local residents via the energy supplier. Assumed rates for the procurement and retail of energy under this model have been assumed based on average market prices and compared to the counterfactual of energy procurement through existing normal supplier tariffs. A target range has been set in the model to beat the market price that can be obtained by consumers which will then influence the overall scheme investment case.

Other options available include a sleeved PPA to commercial/industrial users or virtual PPA to a range of other suppliers which will provide different returns. However, these have not been explored in detail given the focus on local community decarbonisation.

8.2 Funding

8.2.1 Community Owned Scheme

Different ownership and funding schemes are available for community energy organisations and novel commercial models are being developed as this sector gains traction in the energy sector and is considered increasingly attractive by investors. Two examples include:

Community Municipal Investment bonds. Companies such as Abundance energy are beginning to offer this solution working with Local Authorities who borrow money from local residents through a crowd funding mechanism. The investors then receive a near guaranteed payback typically above 1.2% which is considered competitive when compared to current savings rates.

Energy Cooperative – organisations such as Energy4All form local cooperatives. Membership fees can range typically from £250 to £100,000. The Co-op procures the renewable system and any profits resulting are shared with the members. This ensures also revenues are distributed locally and can also be reinvested locally if the members so desire.

Both of these mechanisms can also prove a viable approach to providing access to low carbon systems from the whole community where otherwise those less affluent would not be able to afford the transition.

Licence Lite - In addition to the above, it is now possible for a community energy organisation to become an energy supplier through the use of the Licence Lite mechanism provided by Ofgem (https://www.ofgem.gov.uk/sites/default/files/docs/2015/04/482_an_introduction_to_licence_lite_factsheet_web_0.pdf)

This may be an attractive option for a community energy SPV to become a licensed supplier allowing it to directly sell energy to local communities. Whilst normally becoming an electricity supplier will incur high overheads, the License Lite mechanism is an alternative approach that can be considered for smaller organisations which removes some of the financial and technical barriers of joining the market and involves joining with an existing third-party supplier. There are a range of options for parties wishing to supply energy to consumers. Uniquely, Licence Lite:

- enables market entry where your organisation does not have the capacity to interact with the technicalities of the energy system
- supports a reliable and potentially more favourable market for distributed electricity generation (compared to selling in the wholesale market)
- allows a direct relationship with your customers.
- A wide range of bodies may apply for a Licence Lite direction.
- Customers may be domestic and / or nondomestic, and suppliers may contract with generators or own the generation themselves.

Novel commercial models combining the above now allow the opportunity for local communities not only to participate and invest directly in local renewable energy infrastructure but then to also directly procure energy off the scheme at a lower rate than alternative supplier arrangements. Revenues from energy sales and procurement can then be circulated back into the local economy.

9 Carbon assessment

The carbon emissions of the network have been calculated based on BEIS projections. Two sets of results are shown:

- **Heat network emissions**: indicating the carbon savings from the heat network compared to the 'counterfactual' of oil boilers
- **Household power emissions:** indicating the carbon savings that can be made to the household's power supply compared to the 'counterfactual' of grid electricity import

The heat fraction split for each scenario is as reported in section 7 and assumes an average air-source heat pump COP of 2.5 (250% efficiency) and an oil boiler efficiency of 85%.

Carbon emission factors

Carbon emission factors for electricity are based on the BEIS 2019 carbon factors of fuel[3]. The electricity grid carbon factor varies over time as predicted by BEIS. The modelling assumes all wind and power electricity generation have no associated emissions. Emissions from the biogas CHP are displaced using the BEIS long run marginal (public sector) projections.

BEIS[4] carbon factors have been used for the following fuel types:

- Biogas - 0.00021 kgCO2e/kWh
- Biomass (wood chip) - 0.0155 kgCO2e/kWh
- Burning oil - 0.24666 kgCO2e/kWh

9.2 Heat network emissions

Figure 9—1 shows the projected carbon emissions savings of the heat network across 40 years. Each option sees large carbon savings of over 90% against the counterfactual. This is mainly due to the heat pump operating mainly off zero carbon wind and solar generated electricity, with low reliance on grid import at the energy centre. Due to the displaced emissions from the biogas CHP, Option C sees negative carbon emissions each year.

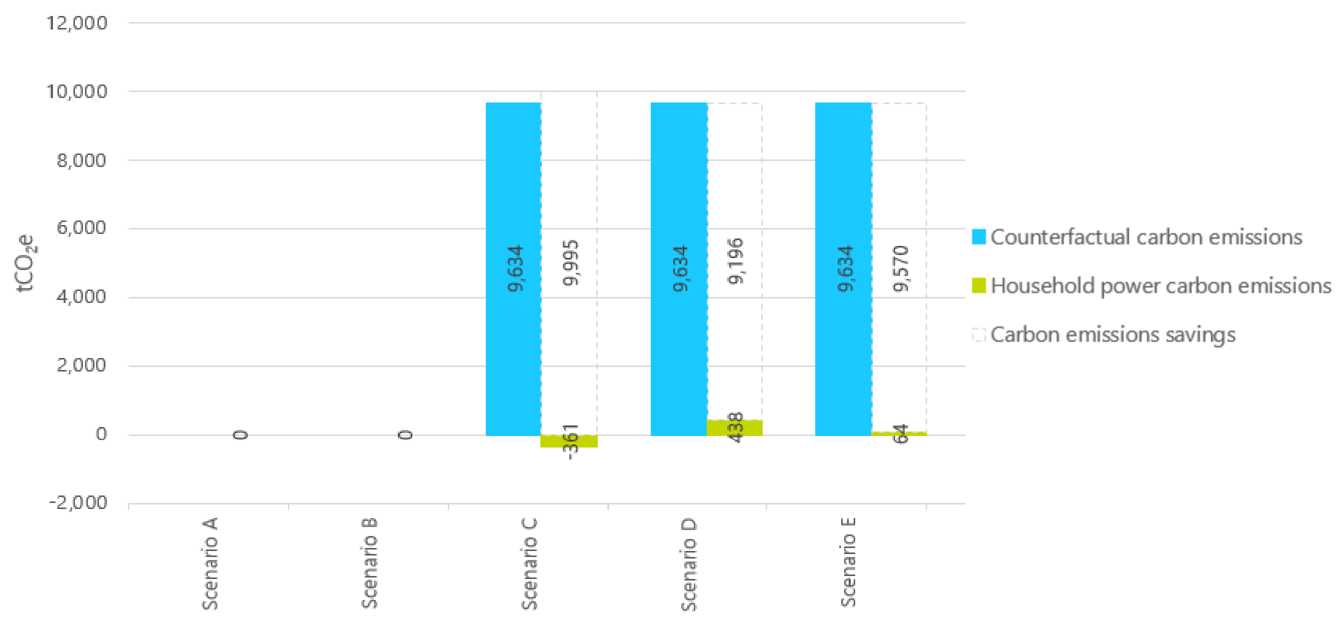


Figure 9—1 Heat network carbon emissions over 40 years

9.3 Household power emissions

Figure 9—2 indicates the possible carbon savings to the household power supply compared to the counterfactual of 100% grid import for each option.

Options A and B have significantly increased carbon emissions due to the ASHP power demand of the 100% electrified heating solution. There are no power carbon savings associated with Option A as there is no virtual PPA in place and household import all electricity from the grid. In Option B, half of the household's power is imported via virtual PPA, significantly reducing their carbon emissions.

The carbon savings of the remaining options arise from the percentage of electricity provided via virtual PPA from the renewable electricity generation (assuming there are no emissions arising from virtual PPA electricity consumption).

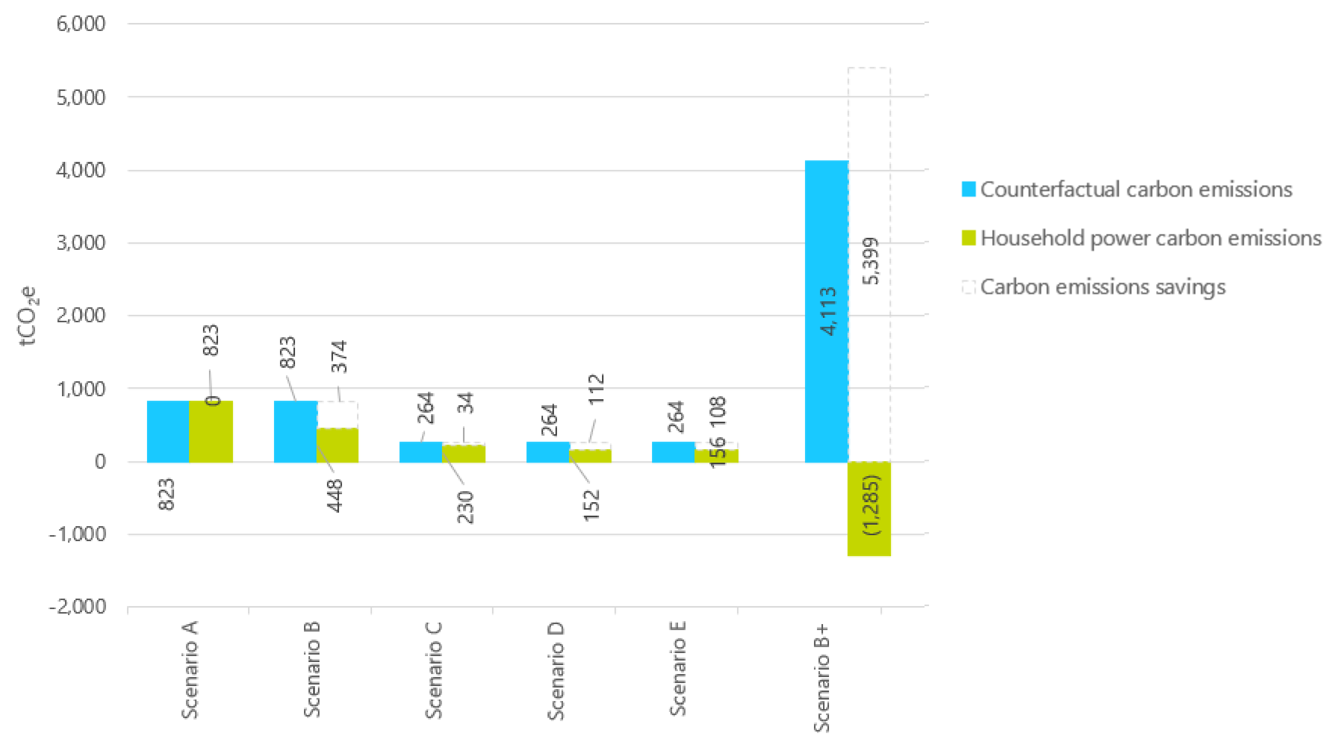


Figure 9—2 Total village household power emissions over 30 years

[3] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020

[4] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2020

10 Conclusions & Next Steps

This study finds that 3 of the 6 modelled scenarios achieve positive cashflow during year on year operation, being scenarios B / B+ and scenario E. These positive cash flows become more appealing when considering implementation of RHI or other government subsidy to help justify the investment case.

When considering the NPV of each scenario over a 40-year timeframe, no scenario achieves a return on investment with positive cashflow scenarios B & E showing relatively static NPV's.

Scenario B+ achieves ~40% return on the initial investment which suggests that, with appropriate low interest funding and subsidy such a scheme could be taken forward for more detailed investigation. A key next step will be to determine whether there is sufficient capacity within the NPG network and any reinforcement requirements to support additional power demands of nearby communities, should they commit to such a scheme

The development of a heat network to serve the village is not considered economically feasible due to the low heat density of the village. A key next step will be to determine whether there is sufficient capacity within the NPG network and any reinforcement requirements to support additional power demands of nearby communities, should they commit to such a scheme.

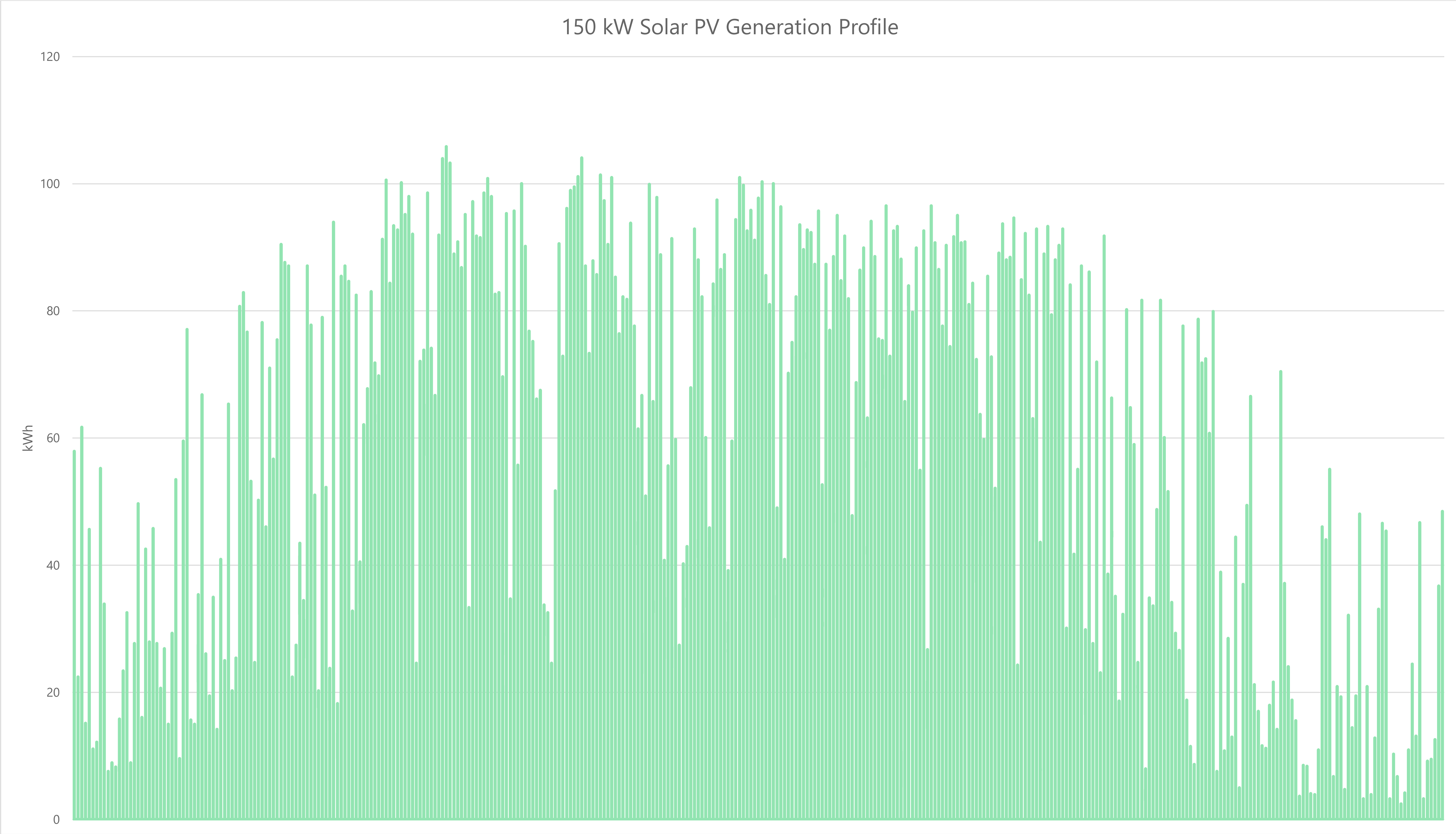
Analysis suggests that decentralised ASHP heating solutions will offer residents the maximum cost and carbon savings, with high up-front costs but overall cost savings over the plant lifetime. Residents should seek government subsidy in the form of RHI funding (or equivalent replacement scheme) as well as the Green Homes Grant to improve energy efficiency within properties before implementing heat pumps.

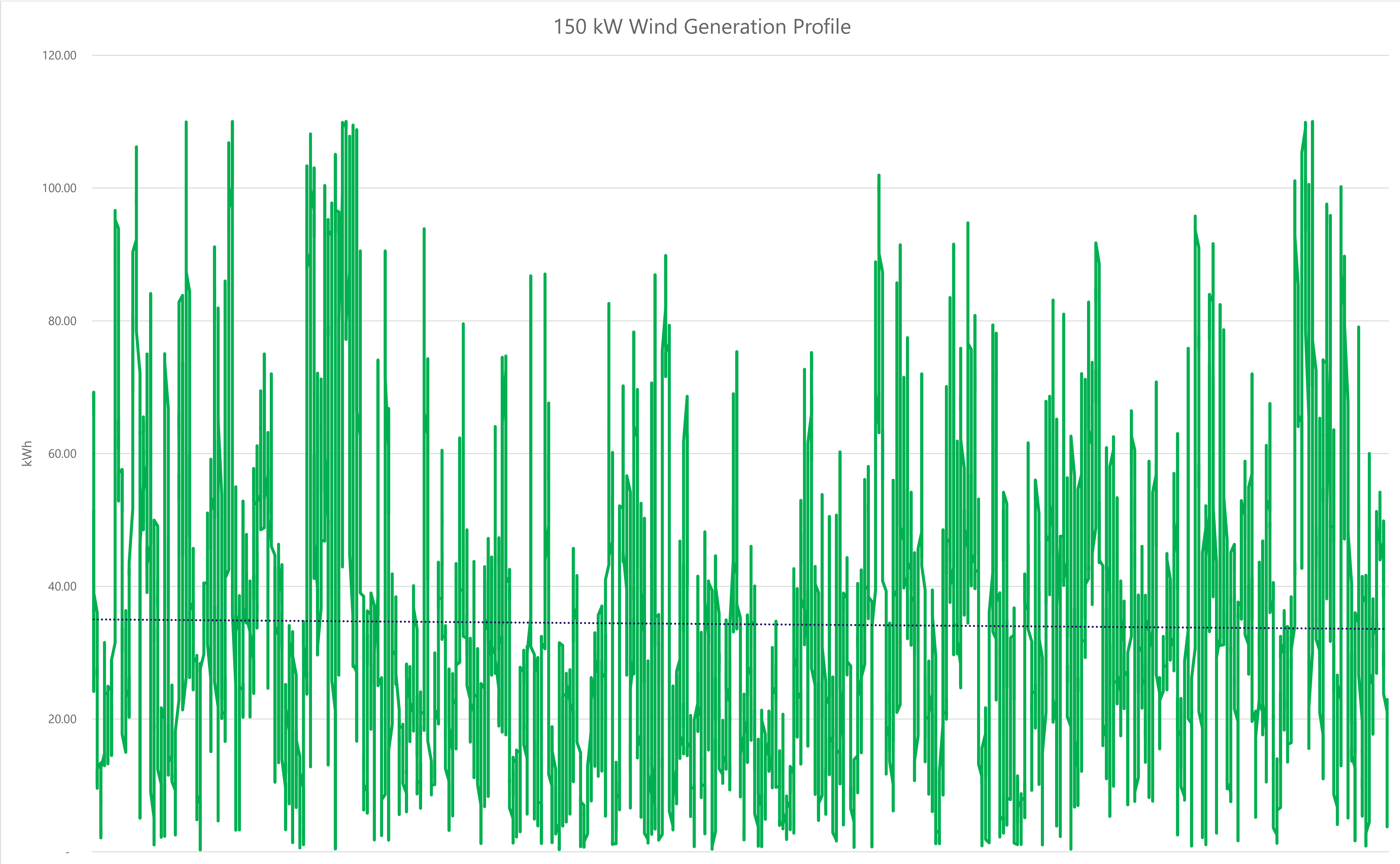
When considering renewable power exported from renewables installed at the farm, securing the right PPA agreements and providing the option for local ownership of the scheme in conjunction with supply local residents will result in greater income for an SPV due to the higher sales price vs. standard grid export rate as well as directly contribute to the affordability and accelerated transition of low carbon heat and power in local communities. Given the suitable land availability at the farm, the willingness of the landowner to develop a renewable energy scheme, and the level of interest from key village stakeholders a sensible next step would be to determine local community interest in supporting the development of a community energy SPV for both the development of the renewable energy system and procurement of local energy

Appendix A Weighted Matrix Scenario Modelling

	Scenario	Stand alone GSHP	Stand alone ASHP	Private Power network for Village	AD + CHP lead heat source at farm	Heat Pump lead source at farm	Heat Pump lead source at farm + Large Renewables - WITH grid upgrade	Heat Pump lead source at farm + Large Renewables - NO grid upgrade
	Pros	- Higher efficiency vs. ASHP - Avoided costs of central heat network - Low risk to programme, individual dwellings implement when required	- CAPEX savings vs. GSHP - Avoided costs of central heat network - Minimal spatial requirements - Low risk to programme, individual dwellings implement when required	- Low carbon heat alternative power source for village - Can offset requirement for grid reinforcement if village moves towards electrified heating - Good availability of land nearby to site renewables / batteries	- Good availability of feedstocks on site and locally sourced to power - Good spatial availability to deploy and willingness from land owners to implement - Proven technology	- Low carbon source of heat centralised heat - Centralised infrastructure at farm requires grid capacity upgrades only there - Low maintenance	- Low carbon source of heat centralised heat - Centralised infrastructure at farm requires grid capacity upgrades only there - Low carbon heat alternative power source for village - Good availability of land nearby to site renewables / batteries / hydrogen	- Low carbon source of heat centralised heat - Centralised infrastructure at farm requires grid capacity upgrades only there - Low carbon heat alternative power source for village - Good availability of land nearby to site renewables / batteries / hydrogen - no requirement for grid reinforcement
	Cons	- High CAPEX vs. ASHP - Spatial requirement to implement boreholes vs. ASHP - Requirement to implement building envelope improvement measures at dwelling level	- Lower efficiency vs. GSHP - Spatial requirement to implement boreholes vs. ASHP - Requirement to implement improvement measures at dwelling level	- CAPEX intensive - Requires installation of new network - Requires buy in from majority of village to justify investment - Renewable system sizes may need to be oversized to account for 7 days outage	- High risk outages and not producing sufficient biogas without proper operation and constant introduction of feedstocks to process - High maintenance requirements - High upfront CAPEX - with lack of funding mechanisms available - Low heat density in village for sales of heat - Programme risk	- Requirement to implement improvement measures at dwelling level to accommodate lower temperature network - High upfront CAPEX - with lack of funding mechanisms available Low heat density in village for sales of heat vs. network cost - Programme risk	- High system complexity - Requirement to implement improvement measures at dwelling level to accommodate lower temperature network - High upfront CAPEX - with lack of funding mechanisms available - Low heat density in village for sales of heat vs. network cost - Hydrogen market not mature - Programme risk	- High system complexity - Requirement to implement improvement measures at dwelling level to accommodate lower temperature network - High upfront CAPEX - with lack of funding mechanisms available - Low heat density in village for sales of heat vs. network cost - Hydrogen market not mature - Excess generation cannot be sold to grid when hydrogen storage full / not functioning - Programme risk
	Scenario	Stand alone GSHP	Stand alone ASHP	Private Power network for Village	AD + CHP lead heat source at farm	Heat Pump lead source at farm	Heat Pump lead source at farm + Large Renewables - WITH grid upgrade	Heat Pump lead source at farm + Large Renewables - NO grid upgrade
Criteria	Weighting							
Cost	**15%**	4	5	2	1	3	1	1
Technological Maturity	**9%**	4	4	4	4	3	2	2
Carbon savings	**12%**	3	2	5	4	5	5	4
Local Impact	**10%**	3	4	2	2	3	1	2
Value for Residents / farm	**15%**	3	4	4	3	3	5	4
Ease of Maintenance	**10%**	3	3	2	1	4	2	2
Programme Risk	**10%**	4	5	3	1	3	1	1
Site Showcase	**9%**	2	1	5	4	3	5	5
Operational Complexity	**10%**	4	4	2	1	3	1	1
	100%	3.35	3.64	3.21	2.3	3.34	2.63	2.46
	Take forward to more detailed TEM?	No - model ASHP instead as standalone heat option	Yes	Yes - model as standalone power option	Suggest no - high risk, AD should be discounted	Yes - model as preferred centralised option, no renewables	Yes - model as preferred centralised option - with renewables	No - risk of sigE5:M24nificant excess generation not being able to export to grid

Appendix B Solar, Wind & Hydrogen Generation Profiles




150 kW Wind Generation Profile
120.00
100.00
80.00
60.00
40.00
20.00
-
kWh


35
30
25
20
15
10
5
0
kg/h Hydrogen Generation

Appendix C CAPEX Costs & OPEX items

Capex items	Option A	Option B	Option C	Option D	Option E	
ASHP						
Decentralised	£ 180,000	£ 180,000	£ -	£ -	£ -	£ 900,000
Centralised	£ -	£ -	£ 306,300	£ 306,300	£ 306,300	£ -
Biogas & CHP	£ -	£ -	£ -	£ -	£ -	
Biogas CHP engine	£ -	£ -	£ 65,000	£ -	£ -	£ -
Biodigester	£ -	£ -	£ 200,000	£ -	£ -	£ -
Hydrogen	£ -	£ -	£ -	£ -	£ -	
Electrolyser	£ -	£ -	£ -	£ -	£ 1,304,800	£ -
Power	£ -	£ -	£ -	£ -	£ -	
Wind farm	£ -	£ 330,000	£ -	£ 330,000	£ 330,000	£ 330,000
Solar PV farm	£ -	£ 180,000	£ -	£ 180,000	£ 3,600,000	£ 3,600,000
Energy Centre	£ -	£ -	£ -	£ -	£ -	
Energy centre fit-out & finish	£ -	£ -	£ 50,000	£ 50,000	£ 50,000	£ -
Network Ancillaries	£ -	£ -	£ -	£ -	£ -	
Main DHN pumps	£ -	£ -	£ 4,900	£ 4,900	£ 4,900	£ -
Expansion/pressurisation	£ -	£ -	£ 1,100	£ 1,100	£ 1,100	£ -
Water Treatment	£ -	£ -	£ 21,000	£ 21,000	£ 21,000	£ -
Dirt separator and deaerator	£ -	£ -	£ 4,000	£ 4,000	£ 4,000	£ -
Controls	£ -	£ -	£ 25,000	£ 25,000	£ 25,000	£ -
Thermal Store	£ -	£ -	£ 10,000	£ 10,000	£ 10,000	£ -
DHN	£ -	£ -	£ -	£ -	£ -	
Pipe and trench costs	£ -	£ -	£ 1,400,000	£ 1,400,000	£ 1,400,000	£ -
Building Connection	£ -	£ -	£ -	£ -	£ -	
Building HIUs	£ -	£ -	£ 35,700	£ 35,700	£ 35,700	£ -
Non resi buildings heat meters	£ -	£ -	£ 3,900	£ 3,900	£ 3,900	£ -
Retrofitting of heating system	£ 600,000	£ 600,000	£ 360,000	£ 360,000	£ 360,000	£ 3,000,000
Electricity upgrades	£ -	£ -	£ -	£ -	£ -	
Electricity Upgrade (315kVA)	£ 40,000	£ 40,000	£ -	£ -	£ -	£ 200,000
Electricity Substation (1MVA)	£ -	£ 150,000	£ 150,000	£ 150,000	£ 150,000	£ 1,200,000
Other Costs	£ -	£ -	£ -	£ -	£ -	
Testing and commissioning (3%)	£ 24,600	£ 44,400	£ 79,100	£ 86,500	£ 228,200	£ 222,000
Prelims (8%)	£ 65,600	£ 118,400	£ 210,900	£ 230,500	£ 608,500	£ 592,000
Design fees (5%)	£ 41,000	£ 74,000	£ 131,800	£ 144,100	£ 380,300	£ 370,000
Contingency (20%)	£ 190,200	£ 343,400	£ 611,700	£ 668,600	£ 1,764,700	£ 1,717,000
TOTAL	**£ 1,141,400**	**£ 2,060,200**	**£ 3,670,400**	**£ 4,011,600**	**£10,588,400**	**£12,131,000**

Opex items	Option A	Option B / B+	Option C	Option D	Option E
PV farm		x		x	x
Wind farm		x		x	x
Central heat pump			x	x	x
Individual ASHP	x	x			
Farmland rental		x	x	x	x
Thermal store			x	x	x
Heat network			x	x	x
Hydrogen electrolyser					x
CHP & biodigester			x		
Biomass boiler			x		
Water consumption £/litre					x

Appendix D Resident Questionnaire

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