Waste heat recovery from electrical substations

Gareth Davies, PhD **Henrique Lagoeiro, PhD** **Akos Revesz, PhD**

Graeme Maidment, PhD, PE

ABSTRACT

The transformation of voltages leads to two types of energy losses in the form of heat, namely no-load losses which are inherent to the transformer and associated with its core; and load losses, caused by the resistance of the windings, which are a direct function of the electrical loading. This paper investigates how the waste heat generated by electrical transformers could be captured and reused via district heating networks. At first, the current availability of waste heat from transformers in the UK is assessed based on data from distribution network operators (DNOs). Potential methods for recovering waste heat from transformers are then presented, and the achievable benefits are discussed based upon carbon and cost savings against conventional heating technologies.

1. INTRODUCTION

In order to meet the UK's target of net zero greenhouse gas emissions by 2050 [Climate Change Committee, 2019], many new low or zero carbon technologies will need to be adopted to replace current fossil fuel based, high emissions technologies. One area of focus is heating and cooling i.e. both industrial and domestic, which currently accounts for approximately 33% of total UK emissions, and is mainly fuelled by natural gas. One potential source of low carbon heat is to use waste heat from essential processes, which is normally released to the environment. The current study investigates one such heat resource, namely the waste heat generated by transformers found in electrical substations.

Reusing recovered waste heat generally involves transferring the heat to water e.g. using a heat exchanger, and then using the water to transport the heat to the user (or many users) through a pipework system. This is often termed a district heating network (DHN) [Energy Saving Trust, 2021]. Using DHNs for distributing waste heat is generally only economically viable if located in an urban area with a dense population of potential users, and with the waste heat source nearby.

The earliest DHNs used high temperature (i.e. 100°C and above) steam and water e.g. 1st and 2nd generation (1G and 2G) DHNs. However, subsequently operating temperatures have steadily decreased for successive generations of DHN i.e. 3G, 4G and 5G networks, with the latest (5G) networks operating at close to ambient temperature [Revesz et al, 2020]. A heat pump is also often used in conjunction with the DHN to upgrade the temperature either for transfer from the waste heat source to the DHN, or prior to transfer from the DHN to users [Foster et al, 2016]. Waste heat generated by electrical substation transformers is generally within the range 20-70°C, so heat pump upgrade is often needed.

In this paper, the reasons for heat being generated by transformers and the main cooling methods used are discussed, then options for heat recovery from transformers e.g. by integrating with the cooling system, are considered. The transformers most suitable for implementing heat recovery systems are discussed and the distribution of transformers across the UK are presented in the form of Geographic Information System (GIS) maps [QGIS, 2021]. Subsequently, the potential performance of the waste heat recovery systems proposed were evaluated using models, and the % savings in energy, CO_2e emissions and costs when compared to conventional heating systems, were calculated. Finally, the conclusions from the study are presented, together with recommendations for the next steps to be taken in the development of these heat recovery systems.

Gareth Davies is a Senior Research Fellow, **Henrique Lagoeiro** is a Research Fellow, **Akos Revesz** is a Senior Research Fellow and **Graeme Maidment** is a Research Professor, in the School of Engineering, London South Bank University, London, UK.

2. WASTE HEAT FROM TRANSFORMERS

2.1 Transformer heat losses

There are two types of losses that occur in transformers, namely load losses and no-load losses. Load losses occur due to the resistance of the copper windings and are proportional to the electrical current squared. However, no-load losses arise from both hysteresis losses and eddy current losses, which occur whenever the transformer is energised, but no power delivery i.e. load, is required. The no-load losses are constant, while the load losses vary with the power drawn from the transformer. The total losses from the transformer are the sum of the load and no-load losses [Kennedy, 1998]. Manufacturers supply a nameplate with data on expected losses for each transformer as a percentage of the connected load. For example typical values have been estimated to be: load losses of 0.65%, and no-load losses of 0.05%, based on a range of transformer capacities between 25 and 125 MVA, An equation expressing the heat losses in terms of capacity and electrical loading is shown below [Bowman et al, 2019].

$$\dot{Q}_{heat\ loss} = C \times (0.0065L^2 + 0.0005) \quad \text{----------------------- (Eq. 1)}$$

Where: $\dot{Q}_{heat\ loss}$ is total heat loss in); C is the total capacity of the transformer in MVA; and L is the electrical loading, expressed as a fraction of the total heat load capacity.

The percentage of load and non-load losses vary between individual transformers, as indicated by their nameplates. However, the average heat loss from transformers has been suggested as 0.5% of load [Faulkenberry and Coffer, 1996], and the heat losses predicted by Eq.1 are of this order.

2.2 Transformer temperatures and cooling methods

Generally, for transformers with capacities > 15 MVA, heat dissipation from the core and windings is regulated by either natural or forced circulation of mineral oil through the transformer core i.e. entering at the bottom and exiting at the top. This is termed the internal (or primary) cooling medium. The heat extracted by the oil is then transferred to an external (or secondary) cooling medium e.g. air or water, which is again regulated by either natural or forced flow. The different cooling system configurations are described by a series of letters, for example ONAF indicates naturally circulated oil as the primary coolant, with forced air as the secondary coolant; while OFWF indicates forced oil circulation as primary coolant, and forced water circulation as secondary coolant. The transformers of greatest interest for heat recovery and reuse are those with the largest capacities e.g. > 60 MVA, which will generally use forced oil cooling combined with forced air or water cooling i.e. OFAF or OFWF.

The highest temperatures in the transformer are within the windings, termed the hot spot temperature, which is typically 15 K (27°R) higher than the top oil temperature, which is defined as the average temperature of the oil exiting the transformer and the oil pocket temperature (representing the temperature of the oil in the transformer oil tank) [Roslan et al, 2017]. The maximum allowable temperature rise above the external cooling medium, for the winding hot spot, is 78 K (140°R) and the maximum rise for the top liquid temperature is 60 K (108°R) [BSI, 2011].

In the current study, the top and bottom liquid temperatures for a transformer operating under a range of specified electrical loadings were estimated using the method described by [Petrovic et al, 2022], whereby the steady state top oil temperature rise was calculated as:

$$\Delta\theta_{to} = \Delta\theta_{tor}\left(\frac{1+RK^2}{1+R}\right)^x \quad \text{------------------------ (Eq. 2)}$$

Where: $\Delta\theta_{to}$ is the steady state top oil temperature rise in K (or °R); $\Delta\theta_{tor}$ is the rated steady state top oil temperature rise in K (or °R), assumed to be 55 K (99°R); R is the ratio of load losses to no-load losses at rated load; K is the current load, as a fraction of total capacity; and x is the oil exponent, assumed to be 1 for a forced oil cooled transformer. The steady state bottom oil temperature rise is calculated as:

$$\Delta\theta_{bo} = \Delta\theta_{to} - (\Delta\theta_{tor} - \Delta\theta_{bor})\left(\frac{1+RK^2}{1+R}\right)^x \quad \text{---------------------- (Eq. 3)}$$

Where: $\Delta\theta_{bo}$ is the steady state bottom oil temperature rise in K (or °R); $\Delta\theta_{bor}$ is the rated bottom oil temperature rise in K (or °R), assumed to be 33 K (59.4°R). Other parameters are as defined above.

The top and bottom oil temperatures θ_{to} and θ_{bo} were calculated from the top and bottom steady state oil temperature rises $\Delta\theta_{to}$ and $\Delta\theta_{bo}$ by adding them to a reference temperature θ_{ref}, which in the case of OFAF cooled transformers was the ambient air temperature, and for OFWF cooled transformers was represented by the water temperature at the inlet to the oil to water heat exchanger. The equations (Eq. 2 and 3) reported by [Petrovic et al, 2002] were derived from equations in the International Standard for transformers [IEC, 2018]. The resolution and range of applicability for these equations will be investigated in future planned experimental work.

2.3 Heat recovery approaches for transformers

Recovering heat from transformers requires linking of the waste heat recovery system to the existing cooling system. As mentioned above, the internal cooling medium for the transformers of interest is usually oil, which is circulated through the core either naturally or by pumping (i.e. forced). The heat carried by the oil is then transferred (using a heat exchanger), to an external medium, namely either the outside air or water. Recovering the heat for transfer to a DHN (other than for a 5G network or ambient loop), generally requires its temperature to be first upgraded using a heat pump (HP). Therefore, a HP evaporator heat exchanger was placed either within the primary or secondary coolant loops to absorb the waste heat, and the HP then used to increase its temperature before delivery to the DHN. A number of options for configurations for transformer heat recovery systems are presented in Figure 1 (a) to (c), although many more configurations are possible. Figure 1 (d) shows how they can be linked to a DHN.

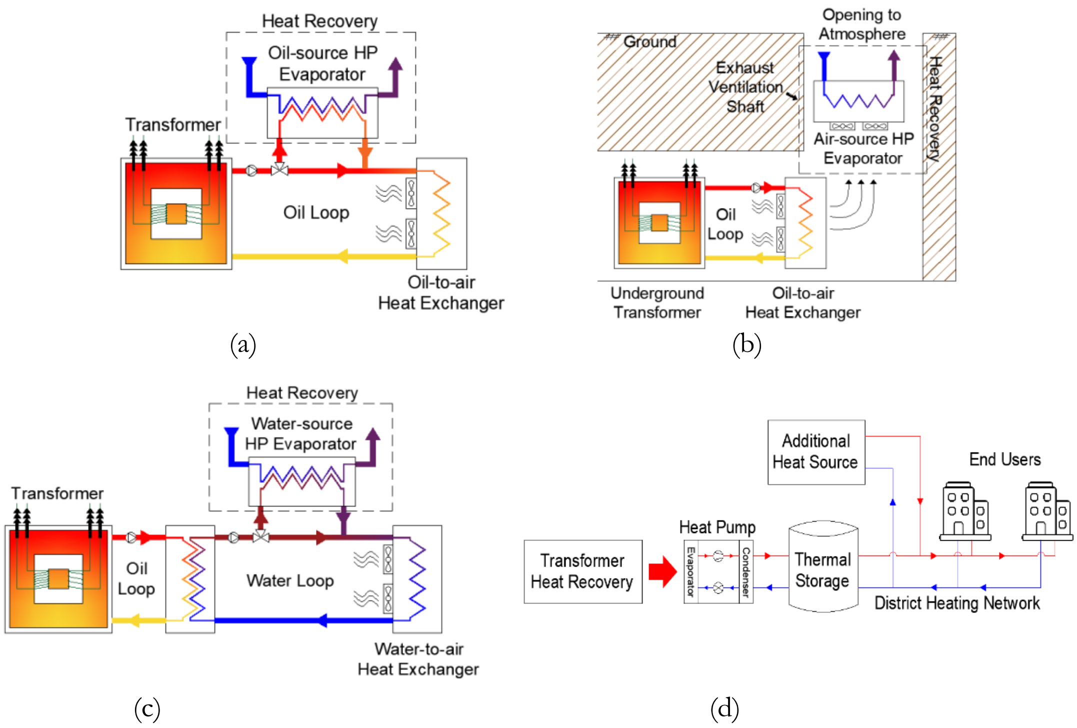


Figure 1 Potential electrical transformer heat recovery options, for: (a) oil forced air forced (OFAF) cooling system; (b) subterranean oil forced air forced (OFAF) cooling system; (c) oil forced water forced (OFWF) cooling system; (d) overall heat delivery system comprising heat recovery, HP, thermal storage and district heating network components.

For each of the transformer heat recovery systems, the original cooling system was left in place to act as a backup, in case of failure of the waste heat recovery system. Heat recovery systems could either be incorporated into new transformer designs or retrofitted to existing transformer cooling systems.

Figure 1 (a) shows a cooling system consisting of oil circulating through the transformer core, which is then pumped through an externally located oil to air heat exchanger, to dissipate the heat to the atmosphere. To recover this heat, the heated oil exiting the transformer is first passed through an oil to refrigerant HP evaporator heat exchanger, whereby most of the heat carried by the oil is transferred to the HP and upgraded before delivery to a DHN. Any remaining heat carried by the oil is dissipated by passing through the original (legacy) oil to air heat exchanger.

In Figure 1 (b), the transformer is sited in a subterranean location. The cooling system normally operates similarly to that shown in Figure 1 (a), with oil circulated through the transformer core and then pumped through an oil to air heat exchanger, where the heat is dissipated to the air, and then extracted to the outside via a ventilation shaft. The heat recovery system involves transferring heat from the shaft air to a HP using an air to refrigerant HP evaporator heat exchanger located in the ventilation shaft.

Figure 1 (c) again involves circulating oil through the transformer core to remove the heat, with the oil then pumped through an oil to water heat exchanger transferring the heat to water, before dissipating the heat to air using a water to air heat exchanger. The heat recovery system involves placing a water to refrigerant HP evaporator heat exchanger within the (secondary coolant) water loop.

Figure 1 (d) shows the overall heat delivery system, applicable to all three transformer heat recovery configurations. It comprises the transformer heat recovery system i.e. heat source, HP, thermal store (to help with meeting peak heat demand), and district heating network (DHN), with the potential for incorporating additional heat sources, to distribute the recovered heat to end users.

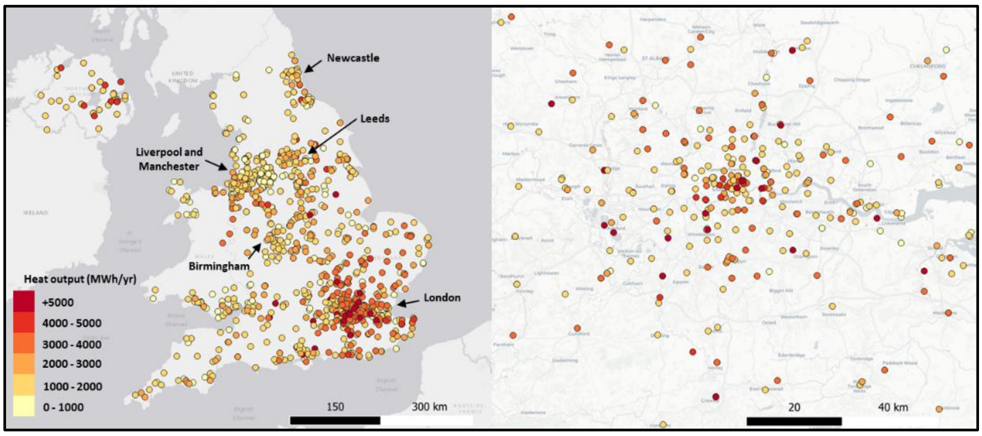
2.4 Types of transformers suitable for applying heat recovery systems

Large scale electrical power generation sites are generally located remotely to urban areas, and electricity often needs to be transmitted over long distances i.e. several hundred kilometres (miles), from power stations to end users. To minimise losses, long distance electricity transmission is carried out at high voltages (HV) e.g. 400 kV in the UK. At the end of the main transmission lines, electrical substations known as Grid Supply Point (GSP) substations are sited, containing transformers to step down the voltage e.g. from 400 to 132 kV. These substations have capacities of several hundred MVA and are located in rural areas [Bowman, 2019]. Bulk Supply Point (BSP) substations contain transformers which further step down the voltage e.g. from 132 to 33 kV. BSPs generally have slightly lower capacities than GSPs and are typically located on the edge of large towns [Bowman, 2019]. Primary substation transformers then step down electricity voltages again e.g. from 33 to 11 kV in the UK. These substations have lower capacities, of the order of tens of MVA and are located in urban areas close to residential streets and commercial areas [Bowman, 2019]. Secondary or distribution substations, are located close to end users and reduce the voltage from 11 kW to 400 V or 240 V, in the UK, prior to use, but have much lower capacities than primary substation transformers.

The most useful types of electrical substations for heat recovery are BSP and Primary substations [Bowman, 2019]. There are estimated to be of the order of 5800 substations of these types, in the UK [Northern Powergrid, 2015]. District heating provides only a small proportion (2%) of the UK's heating at present, but a large expansion of district heating is planned in the next few years, as part of the drive towards net zero carbon emissions [Climate Change Committee, 2019]. Electrical substations in the UK are widely distributed and could provide a useful low carbon heat source for many of these networks.

2.5 Distribution of transformers suitable for heat recovery in UK

The distribution of electrical substations with greater than 60 MVA capacity across England, Wales and Northern Ireland, is shown in Figure 2 (a). (The distribution of substations in Scotland in relation to waste heat has been reported elsewhere [Sinclair and Unkaya, 2020].) A more detailed map showing electrical substations in the Greater London area is shown in Figure 2 (b) below.



(a) (b)

Figure 2 Locations of electrical substations: (a) across the UK (excluding Scotland); (b) in the Greater London area

Figure 2 (a) shows a concentration of substations in urban areas, for example, clustered around the major cities of Newcastle, Liverpool, Manchester, Leeds, Birmingham and London, in the UK. The high heat densities associated with these cities represent a great opportunity for the development of heat networks, as identified by [BEIS, 2021]. The Greater London area shown in Figure 2 (b) has the largest concentration of substations in the UK, with potential for providing more than 5,000 MWh (17061 MMBtu) of waste heat per annum. Many primary substations (of a suitable size for heat recovery) are sited close to industrial districts and are also likely to be located close to other large users e.g. university campuses. In future work, it is also planned to map the location of suitable substations to determine their proximity relative to potential users of recovered heat, and thereby identify specific opportunities.

2.6 MODELLING OF HEAT RECOVERY SYSTEMS FOR TRANSFORMERS

Using half-hourly electrical loading data provided by an electricity supply company in the UK [Bowman, 2019], the annual heat loss profile for a 90 MVA BSP substation transformer, with OFAF cooling, was determined using Eq.1. The heat loss data was then averaged to provide monthly heat loss values across the year. Top oil temperatures for the transformer were estimated using Eq. 2, based on the electrical loading data, with the reference temperatures assumed to be ambient air. The ambient air temperatures were based on weather data for the Southampton area of the UK, where the transformer was located [CIBSE, 2016]. Figure 3 shows the resulting heat loss and top oil temperatures profiles.

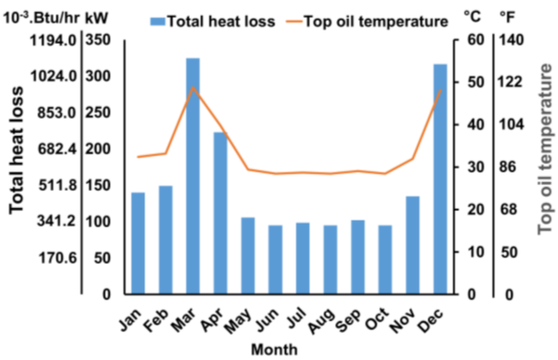


Figure 3 Calculated monthly heat loss rates and top oil temperatures for 90 MVA transformer

A spreadsheet model was developed to evaluate and compare six heat recovery scenarios based on the three configurations shown in Figure 1. The model incorporated key design details for the heat recovery systems, including temperature of the heat source, quantity of heat recovered, mass flow rates for the coolants (both primary and secondary), specific heat capacities, heat exchanger surface areas and heat transfer coefficients.

Heat transfers using heat exchangers between the primary and secondary coolants and between the heat source and HP evaporator refrigerant, were simulated to determine their effects on reducing the temperature of the recovered heat. The effects of additional pressure drops due to the introduction of heat exchangers into the circulating coolant flow have been neglected, so the main energy input for the heat recovery system was the electricity needed for the HP, to upgrade the temperature of the recovered heat before delivery to a DHN. Some additional pumping power would be needed to transport the upgraded heat between the HP and DHN and some heat loss would result, depending on the distance between the transformer and the network, however, in practice, this would need to be determined on a case by case basis. For the current model, the distance was assumed to be small, so pumping power and heat losses would also be small, and the same for each of the scenarios modelled, so were not included.

Parameter values adopted and assumptions used for the six heat recovery scenarios included: (i) the quantity of heat recovered, whether 100% or a smaller percentage of the total transformer heat loss; (ii) reference temperatures depending on the secondary coolant used, either ambient air, or 20°C (68°F) for water (iii) mass flow rates for oil 15 kg s^{-1} (33 lb s^{-1}), air 15 kg s^{-1} (33 lb s^{-1}) and water 10 kg s^{-1} (22 lb s^{-1}); (iv) standard specific heat values for air and water, and 2000 J kg^{-1} K^{-1} (0.478 Btu lb^{-1} F^{-1}) for mineral oil; (v) for the HP, an evaporator approach temperature of 5 K (9°R) was assumed in each case, enabling the evaporator temperature to be estimated from the coolant inlet temperature; (vi) the HP was assumed to upgrade the recovered heat for delivery to a DHN at 75°C (167°F), with a condenser approach temperature of 5 K (9°R) assumed, and condensing temperature of 80°C (176°F), in each case; (vii) the coefficient of performance (COP) for the heat pump was calculated using the CoolPack software [CoolPack, 2012], based on a standard single cycle, with ammonia as refrigerant, for each heat recovery scenario; (viii) carbon factors for UK electricity of 0.193 kg CO_2e kWh^{-1} (1.45 lb CO_2e $kBtu^{-1}$), and for natural gas of 0.182 kg CO_2e kWh^{-1} (1.37 lb CO_2e $kBtu^{-1}$); electricity costs of £369.3/MWh ($402.5/MWh) and gas of £115.7/MWh ($37.0/Dth) were used in calculating the cost savings. All other parameter values were calculated within the model. The performance of each heat recovery scenario over the course of a year was determined and compared with that for a gas boiler and ASHP, to deliver the same quantity of heat.

3.0 RESULTS

Six potential heat recovery scenarios for transformer heat recovery were modelled to determine their relative performance, as seen in Table 1. The heat recovery scenarios were based on the three basic heat recovery system configurations shown in Figure 1, with two options in terms of the proportion of waste heat recovered i.e. 100% or 60%, being considered, in each case

Table 1 Waste heat recovery scenarios evaluated

Scenario No.	Standard cooling type	Heat transfers prior to HP	Secondary coolant (reference temperature)	HP heat source	Percentage of available waste heat recovered
1	OFAF	core/oil	ambient air	oil	100%
2	OFAF	core/oil	ambient air	oil	60%
3	OFAF	core/oil; oil/air	ambient air	air	100%
4	OFAF	core/oil; oil/air	ambient air	air	60%
5	OFWF	core/oil; oil/water	water 20°C	water	100%
6	OFWF	core/oil; oil/water	water 20°C	water	60%

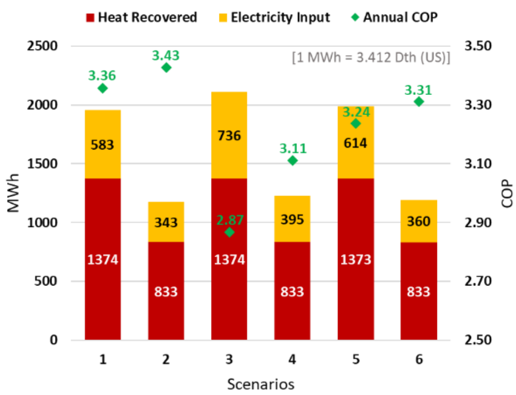
Note: OF = oil forced; WF = water forced; AF = air forced

In Table 1, scenarios 1 and 2 represent the configuration shown in Figure 1 (a), namely direct heat recovery from oil. Scenarios 3 and 4 represent Figure 1 (b), namely heat recovery from air, and scenarios 5 and 6 represent Figure 1 (c), namely heat recovery from water.

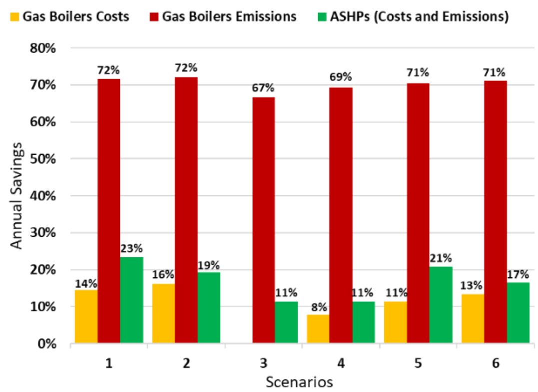
For scenarios 1, 3 and 5, for the purposes of the model, 100% of the transformer waste heat was assumed to be recovered, and the heat exchanger assumed to be of sufficient capacity to capture all of the waste heat, for the transformer loadings considered. However, these were mean monthly values and loadings varied on an hourly basis, with peak loadings likely to exceed these values. Consequently, not all of the waste heat would be recovered. Also, since heat exchanger efficiencies are less than 100%, capturing all of the waste heat would require oversizing the heat exchanger. In practice, the size/capacity of the heat recovery heat exchanger would be limited due to capital cost considerations (which have not been included in the current calculations), and sizing the heat recovery system would need to consider both the expected transformer loadings and how much waste heat could be economically recovered. However, by retaining the original (legacy) cooling system in place e.g. an oil to air, or water to air heat exchanger, the excess heat would still be dissipated to the outside air.

For scenarios 2, 4 and 6, it was assumed that 60% of the maximum monthly heat loss was recovered. This represented the lowest average monthly heat loss determined (in Figure 3), implying it could provide a constant quantity of recovered heat throughout the year, although, in practice, it would also be subject to hourly loading variations. Where only 60% of the waste heat was recovered, it was assumed that this would comprise the highest temperature heat (of the total heat available), so could be upgraded more efficiently by the HP, and would therefore be expected to produce a higher annual COP.

The results from modelling of the six heating system scenarios are shown in Figure 4. Figure 4 (a) shows the results for annual heat recovered and electrical energy input to the HP in MWh (or Dth) and the annual COP for the HP temperature upgrade. Figure 4 (b) shows the percentage annual cost and emissions savings for each heat recovery scenario against gas boilers and ASHPs. It is assumed that gas boilers generate heat from gas with an energy efficiency of 90%.



(a)



(b)

Figure 4 (a) heat recovered, electricity input and annual COP for the six different scenarios; (b) annual costs and emissions for the six heat recovery scenarios compared with gas boilers and ASHPs

4.0 DISCUSSION

It is seen in Figure 4 (a), that when comparing the results for recovery of 100% and 60% of the heat losses, for each of the three heat recovery system configurations, the annual COP was slightly higher for the 60% heat recovery scenarios. Consequently, the electricity input as a proportion of the total heat delivered (represented by the full column height) was reduced for the 60% heat recovery scenarios compared to the 100% scenarios. This was in line with expectations, since within the model it was assumed that the highest temperature heat only would be recovered for the 60% heat recovery scenarios.

In Figure 4 (b), the annual cost saving for the transformer heat recovery systems compared to gas boilers shows a small increase for the 60% recovery scenarios (2. 4 and 6) compared to the 100% recovery scenarios (1, 3 and 5). This reflects the increases in annual COP in each case. (The cost saving for heat recovery scenario 3 is zero compared to gas boilers.)

Although this suggests that recovering only 60% of the waste heat would be more efficient, it might impact the business case, as less heat would be recovered relative to the capital costs per kWh of heat delivered by the network. However, recovering less waste heat could be more appropriate (i.e. economic) for the largest capacity transformers, or those that operate with high variation in loadings across the year, where the capital costs for a system to recover all of the heat might become too high.

Figure 4 (b) also shows that the annual % CO_2e emissions savings for the transformer heat recovery systems ranged from 67 to 72% compared to gas boilers, and between 11 and 23% for both emissions and costs compared to ASHPs. Savings were lower for the air source heat recovery scenarios (3 and 4).

There was a small increase in annual COP when using oil as the heat source, compared to water, as seen in Figure 4 (a). The annual COPs of the water source heat recovery scenarios (5 and 6) were expected to be lower due to the temperature drop resulting from the additional heat transfer step between the primary (oil) and secondary (water) coolant, prior to heat recovery. However, this was partially offset by the different reference temperatures used when calculating the top and bottom oil temperatures for the transformer, namely ambient air temperatures for the oil source heat recovery scenarios (1 and 2), and 20°C (68°F) water for the water source heat recovery scenarios (5 and 6). Consequently, the water heat source temperatures for scenarios 5 and 6 were only slightly lower than the oil heat source temperatures for scenarios 1 and 2.

The model results suggested that by using a smaller proportion of the waste heat e.g. 60% of the heat output from the transformer, a steadier rate of heat delivery by the HP could be achieved across the year, although the model was based on average monthly loadings, and loadings will actually fluctuate quite significantly on an hour to hour basis. However an alternative approach that could regulate heat delivery to the DHN, while potentially recovering a larger percentage of the waste heat, would be to incorporate thermal storage. The size of the thermal store would need to be determined in relation to both the heat output profile (Figure 3) and the heat demand profile of users (e.g. a DHN).

Using the steady state top and bottom oil temperature calculation method [Petrovic et al, 2022] provided a simple approach for simulating the temperatures for the oil circulated through the transformer, which were useful for comparing the performance of the different heat recovery scenarios considered. However, future work will include evaluating these oil temperatures in relation to dynamic top oil and hot-spot temperatures for transformers, as defined in the International Standard [IEC, 2018], as well as comparing these values with measured oil temperatures for a range of substation transformers and electrical loadings.

5.0 CONCLUSIONS

The results obtained from the modelling work, reported in Figure 4, show that under typical electrical loadings, significant quantities of heat can be recovered from substation transformers, and after upgrading with a heat pump, can be delivered to end-users at temperatures suitable for reuse. The results showed that this can be achieved efficiently, with substantial energy, carbon and cost savings compared to alternative heating methods such as gas boilers (up to 16 % cost savings and between 57 to 64% CO_2e emissions savings), or ASHPs (cost, CO_2e emissions and energy savings of between 11 and 23%), for the different heat recovery scenarios.

Comparing all of the heat recovery scenarios (1 to 6), the highest annual COPs achieved were for the oil source scenarios (1 and 2) with values of 3.36 and 3.43 respectively, however, the annual COP values for the water source scenarios (5 and 6) were only marginally lower at 3.24 and 3.31 respectively. The annual COPs for the air source scenarios (3 and 4) were lowest, with values of 2.87 and 3.11 respectively.

Therefore, the results suggest that recovering the transformer heat losses directly from the circulating oil offered the greatest opportunities for savings compared to conventional heating methods, although all of the heat recovery methods modelled appeared to be feasible. However in practice, the simplest method of recovering the heat (with least impact on current operating practices) would be to use exhausted air as the heat source.

Future work will aim to validate the results for predicted heat outputs and predicted oil temperatures against measured data from existing transformers under typical operating conditions, and to develop the models to account for additional factors, such as pumping power requirements and heat losses, and meeting a specific heat demand, for example by integration of the recovery system with thermal storage.

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