Innovation Funding Incentive (IFI)

Management of electricity distribution network losses

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1 Background

1.1 Introduction

In partnership, Imperial College and Sohn Associates have investigated various factors relating to the concept of loss-inclusive network design. This work has been conducted in collaboration with UK Power Networks (UKPN) and Western Power Distribution (WPD), the two largest UK DNOs. We are grateful for their contribution to this work.

In distribution network management, design policies and standards are developed and adopted with the key objectives of achieving network reliability and safety at efficient and fair cost. The consideration of losses has also been important, but has been generally subordinate to network managers' primary objectives of safety and reliability.

This Report describes the studies which analyses the nature of losses, their magnitude and the economic justification for loss-inclusive network design.

Copper and iron losses are an inherent feature of electricity distribution. They cannot be eliminated but this Report explores how the network can be managed such that losses are economically efficient. The conclusions on better management of network losses[1] are based upon evidence and analysis concerning not only what is technically feasible and practical, but also what is economically justified.

The loss studies described in this Report have also been placed into a wider, "whole-system" economic policy context to provide affordable and sustainable energy. For example, designing energy efficiency into the distribution network may avoid the need for additional generation. Another example of whole-system thinking would be the harvesting and use of the heat from the distribution network which may be an efficient investment in supplementing more conventional heating provision. An objective of the studies described in this Report is to provide insight into losses which fits with the developments in whole systems energy modelling which in turn is being applied to help policy-makers meet the challenges of decarbonisation, energy security and cost-effectiveness of energy provision.

1.2 Scope and objectives

In distribution network management, design policies and standards are established to meet the objectives of achieving network reliability and safety at efficient cost. The consideration of losses has also been important, but has been generally subordinate to network managers' primary objectives of safety and reliability.

Imperial College and Sohn Associates have worked together on an IFI-sponsored project which has examined the opportunities for moving further towards loss-inclusive network operation and design. This is in contrast to the more traditional approach of peak-driven network operation and design, in which the network is primarily operated, developed and designed to meet peak demand in a safe and reliable manner and in which losses have been considered more as a consequence of design and operational management decisions, rather than an explicit design criterion.

In essence, this Study has been undertaken in order to further develop the concept of making distribution networks as energy efficient as is economically justified, raising awareness of the relevant issues and proposing solutions which take more account of losses in network design.

[1]The term "network losses" is used throughout this report interchangeably with "technical losses".

Copper and iron losses are an inherent feature of electricity distribution. They cannot be eliminated but this Study explores how the network can be managed such that losses are economically efficient. The conclusions on better management of network losses[2] are based upon evidence, views and opinions concerning not only what is technically feasible and practical, but also what is economically justified.

The specific objectives of this work are three-fold:

1. **Understanding and managing losses**: The Study provides both background and insight on distribution network losses as a precursor to control of losses in future network management;
2. **Loss inclusive network design**: Traditionally, network design has been driven by requirements of delivering power reliably and safely. This has not explicitly included the cost of losses and the economic impact of carbon dioxide emissions. A key objective of this work is to now consider the cost of losses within the network designs of the future;
3. **Future developments**: The Study has researched other work which in the future may contribute to further improvements in loss management and extend the consideration of losses to the heat generated from electrical loss. The objective of this work has been to review the extent of knowledge and experience of such work and to assess its potential value.

This work has been broad in scope, considering various causes of loss in today's networks which have been designed in a traditional manner to GB specifications. It also considers the potential networks of the future, meeting new requirements of distributed generation, increased demand and supporting the transition to more efficient use of energy, whilst ensuring that electricity will continue to be affordable.

One key driver of loss reduction is the consequent reduction of carbon dioxide emissions from avoided fossil-fuelled power generation. Clearly the level of carbon dioxide reduction is determined by the extent of loss reduction which may be achieved and the carbon intensity in the mix of generation types (fossil v non-fossil). This is a factor which is considered in the scope of our work. The embedded carbon which is a feature in the manufacture and installation of distribution network plant and equipment has not been directly considered, as previous work demonstrated this is much less significant when compared with the level of carbon dioxide emissions relating to network losses[3,4].

The project has been designed with the objective of developing new knowledge and presenting information on network losses and low-loss design which can both inform the regulatory process in and can assist DNOs with their consideration of losses in network management.

1.3 Format

The core deliverable from the Study is the loss analysis conducted using Imperial's network representative models. Section 2 describes the various drivers of loss in typical GB distribution networks and Section 3 considers various proposals relating to loss-inclusive network design.

In addition to the information in this Report relating to loss management through network design, Section 3 also provides some information on the potential for new materials for further cost-effective development of energy-efficient power networks.

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[2] The term "network losses" is used throughout this Report interchangeably with "technical losses".

[3] "Analysis of distribution losses and life cycle CO_2 emissions". 20th International Conference on Electricity Distribution Prague, 8-11 June 2009. Paper 0560 CIRED2009 Session 1 Paper No 0560.

[4] Mancarella P, Gan CK, Strbac G, 2011, Optimal design of low-voltage distribution networks for CO2 emission minimization, *IET Generation Transmission & Distribution*, Vol:5, ISSN:1751-8687, Pages:38-46.

Section 4 includes the results of the significant work which has been completed on the potential for harvesting and use of heat generated as network loss.

Section 5 considers the implications of this work from technical and regulatory perspectives, followed by conclusions from the work in Section 6.

Several Appendices have been prepared, providing support material to the main body of the Report.

2 Features of network losses

This Study has examined a variety of factors which drive loss in existing and future electricity distribution networks. Much of the work has been conducted using network modelling and analysis tools, to both understand the drivers of losses and to evaluate the potential for better loss management through loss-inclusive network design. In this Section of we consider how various network operation practices and characteristics affect the level of losses in the network, as modelled and analysed using statistical representative network modes and Generic Distribution System tool. These methodologies are further described in Appendix 1.

2.1 Network modelling and analysis

Distribution networks in this analysis are modelled using Imperial's statistical representative network models to reproduce realistic network topologies and network lengths allowing for the characterisation of GB distribution networks of different types. For the purpose of the analysis, we have made use of 10 representative networks, mapping the entire GB distribution network. The 10 representative networks capture the key statistical properties of typical network topologies that can range from high-load density city/town networks to low-density rural networks. The design parameters of the representative networks closely match those of realistic distribution networks of similar topologies. The developed representative networks map the GB distribution networks closely in terms of total number of connected consumers, total overhead LV network length, total underground LV network length, total number of pole-mounted transformers (PMT), total number of ground-mounted transformers (GMT). Table 1 demonstrates that our representative model closely map the GB aggregate values.

Table 1: Mapping of representative networks (RN) onto actual GB distribution networks

Parameter	GB value	RN value	Discrepancy (%)
Number of connected consumers	29,416,113	29,410,374	-0.02%
Overhead LV network length (km)	64,929	64,905	-0.04%
Underground LV network length (km)	327,609	327,822	0.07%
Number of PMT	343,857	343,848	-0.00%
Number of GMT	230,465	230,323	-0.06%
Overhead LV network length per PMT (m)	189	189	-0.03%
Underground LV network length per GMT (m)	1,422	1,423	0.13%

The Extra High Voltage (EHV[5]) network analysis and evaluation of losses is carried out using a number of representative Grid Supply Point (GSP) network models. These models have been calibrated against real networks and the comparison as shown in Figure 1 demonstrates that the GSP models are representative of typical distribution networks in particular with respect to the assessment of energy losses.

[5] EHV is defined as 22kV or above

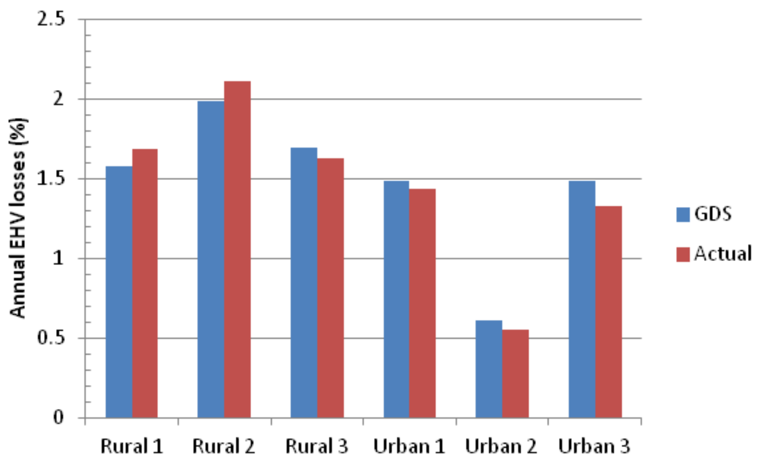


Figure 1: Comparison of actual and estimated losses for GSP models

Figure 2 shows the breakdown of GB distribution losses calculated using representative network models. Annual losses are estimated to be between 5.8% and 6.6% of energy delivered. It can be seen that about three quarters of losses occur in LV and HV networks.

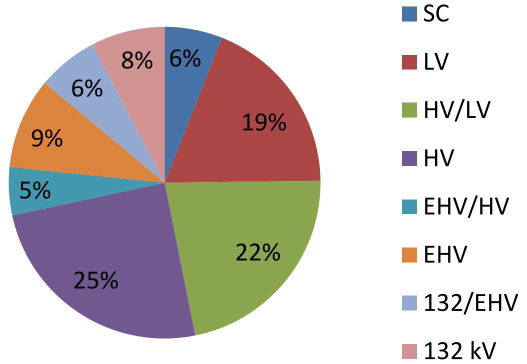


Figure 2: Breakdown of GB losses- SC – service cable, LV – low voltage,

HV – high voltage, EHV – extra high voltage

Losses are found to vary quite significantly depending on the network type, as illustrated in Table 2 and Figure 3.

Table 2: Losses in different network types

Network Type	Losses
Rural	6.0% - 9.1%
Semi-rural	5.8% - 8.2%
Semi-urban	4.9% - 6.4%
Urban	4.2% - 4.9%

The analysis of the breakdown of losses across a typical GB distribution network correlates well with Distribution Network Operators own network studies.

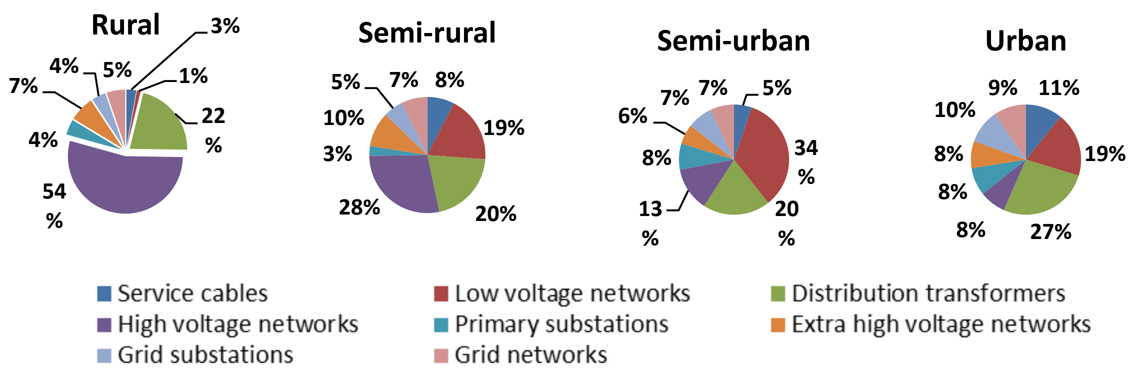


Figure 3: Breakdown of losses across distribution networks in four types of network

In rural networks more than half of the loss occurs in the HV networks. LV network losses are very low due to short feeders and fewer consumers supplied per feeder. The distribution transformers losses are about 22% of the total losses. The rural networks have the highest overall annual losses, approaching about 6.0-9.1% of energy supplied.

Losses in semi-rural type networks are similar to total GB losses with overall losses of about 5.8-8.2% which is expected as the majority of networks are of this type.

In semi-urban networks, the share of losses in LV networks increases and losses in the HV networks decrease. The overall annual losses are about 4.9-6.4% of the energy supplied.

In urban networks, where LV and HV feeders become shorter, the share of losses in distribution transformers increases. However, overall losses are smaller and they account for about 4.2-4.9% of annual energy supplied.

We consider that there is considerably more knowledge of losses to be discovered using alternative loss focused network analysis and design techniques and it will be of benefit to DNOs to become increasingly familiar with such capabilities for loss modelling and analysis.

Our modelling work has been based upon historic demand profiles and that these may change in the future. At this stage of development of loss understanding, assumptions on the nature of these changes will add considerably to the complexity and uncertainty of any analysis. However, consistent with many other views within the industry on future networks, we may expect to see greater demand for electricity and increasing requirements for flatter profiles, which will assist both capacity planning and loss optimisation.

Recommendation 1: The network modelling and analysis tools used in the study are based on calibrated representative network models data. Given the increasing importance of losses, it would be appropriate that DNOs establish the capability of modelling and evaluating loss performance of their present and future networks, under different future development scenarios.

2.2 Power factor and losses

Departure of load power factor from unity will increase losses in distribution networks. Table 3 presents the increase in losses in LV and HV networks due to various power factors of loads and in different representative network types. We observe that greatest increase of losses is in rural type networks when compared to urban networks. For example, if the load power factor is 0.95 the losses are between 5-10% greater when compared with the unity power factor case.

Table 3: Impact of loading power factors on losses increase for different representative network types

Power factor	Representative network types			
	Urban	S-urban	S-rural	Rural
1	0	0	0	0
0.95	5.3%	6.9%	7.7%	10.1%
0.9	10.5%	13.2%	14.6%	18.9%
0.85	16.3%	20.1%	22.1%	29.7%
0.8	22.7%	27.9%	30.6%	-

We also observe that poor power factors, e.g. less than 0.9, would significantly increase losses.

The representative network models have been used to estimate the benefits of installing power factor correction equipment. The benefits have been estimated for improving the power factor to unity from values of 0.8, 0.85, 0.9 and 0.95 across a range of network types. The range of benefits of improving power factor to unity for various network types is given in Table 4.

Table 4: Benefits (£/KVAr) of improving power factor to unity for different network types

Power factor	Urban	S-urban	S-rural	Rural
0.95 → 1	13 – 31	24 – 59	36 – 88	43 – 106
0.9 → 1	40 – 99	73 – 179	105 – 259	126 – 310
0.85 → 1	76 – 188	137 – 337	197 – 485	247 – 608
0.8 → 1	120 – 296	214 – 529	309 – 761	–

The lower values of benefit in the range correspond to 9% discount rate over 20 years and the higher values correspond to 3.5% discount rate over 45 years.

Power factor improvements in different network types range in value from £13 per KVAr (0.95→1, Urban) to £761 per KVAr (0.8→1, Semi-rural).

Typically, the cost of reactive compensation is less than £50/kVAr and there is potential for improvement as may be inferred from the Table above. However, the practical costs of improving power factor will vary enormously from one consumers' premise to another.

From the analysis we make two key observations: (a) poor power factor leads to significant increase in losses and (b) improvements in power factor may be cost effective in a number of cases. One of the key challenges associated with establishing the business case for power factor correction is the lack of data associated with active and reactive power demand in LV and HV networks. Increased level of measurements and general visibility of distribution networks, supported by various smartgrid initiatives and smart meter roll-out, could be used potentially to carry out systematic data collection relating to power factor. It may be noted that the smart metering specification SMETS2 requires four quadrant half-hourly measurement capabilities and there is future potential to identify some sites operating at low power factor.

Better data could then be support a more comprehensive analysis of the impact of power factors on network losses and appropriate evaluations of the economic case for improvements in power factor.

Additionally, demonstration projects may be developed to correct power factor at several identified consumers' locations. The network loss reduction in these projects may be estimated through network studies. From a series of such Case Studies, a picture may be developed of the full potential for loss reduction through power factor improvement.

It may be appropriate to review the incentives in relation to power factor. There has been a longstanding tradition in the GB electricity industry of encouraging and incentivising end-consumers to improve power factor although the impact of power factor penalties within DUoS charges and supply contracts is not necessarily effective. Quantification of the value of reduced losses through power factor correction will inform the right level of charges which should be levied through DUoS tariffs and assist in negotiating the relationship with energy suppliers to bring power factor correction incentives into effect.

Recommendation 2: DNOs to consider carrying out more systematic data gathering associated with power factor to assess the materiality of the issue and to enhance the understanding of the costs and benefits of power factor correction at consumers' premises. The business case for power factor correction may then be developed.

2.3 Phase imbalance

The results of the analysis carried out indicate that the impact of imbalance on losses is very non-linear with small imbalances (<10%) causing an increase in losses of <5% but large imbalances (>25%) causing an increase of >30% in losses[6].

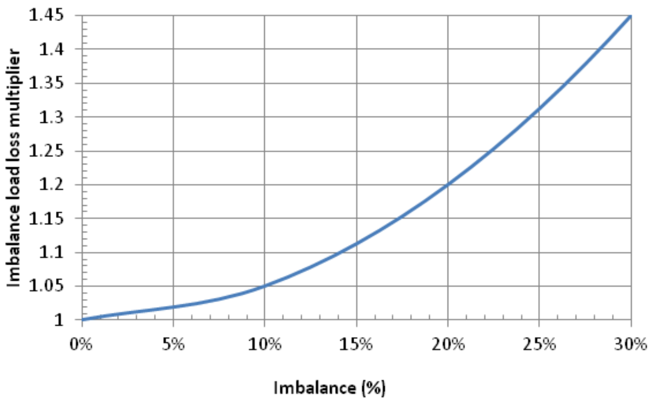


Figure 4: Effect of phase imbalance on losses

Even in the case that end consumers' loads are equally allocated among phases, actual loading of different phases at different times will be unequal which will lead to an increase in electricity losses driven by imbalance.

In addition to LV network imbalances, the application of two-phase 11kV overhead line designs will lead to increase in losses in HV networks. It is not however clear if two-phase overhead circuit solutions are economically efficient, particularly when increase in network losses is considered.

Figure 5 shows the potential benefit of phase balancing for four feeder types. Generally, the level of benefit is proportional to the feeder length. Hence, installation of phase balancing technologies may be more beneficial on longer feeders with greater imbalance. For example, for an underground feeder of 1.1 km and an imbalance of 30%, the possible benefit of reducing losses is in the range from £2,500 to £5,300.

[6] Note that 0% represents a fully balanced network and 100% represents full load on a single phase.

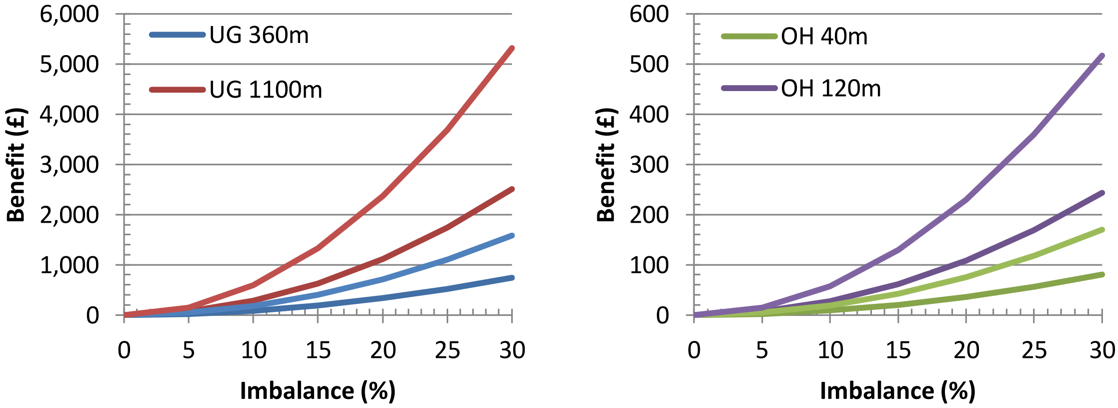


Figure 5: Range of potential phase balancing benefits per feeders; minimum benefit is for discount rate of 9% over 20 years while maximum benefit is for discount rate of 3.5% over 45 years

In addition to the adverse effect on network losses, phase imbalance will also have an undesirable impact on voltage profile and radio interference. It will also reduce the available network headroom as the loading on one of the phases would increase relative to the other phases and this may trigger premature network reinforcement. Although there are several individual cases where phase imbalance is potentially very significant, the overall materiality of the problem is not well understood. Furthermore, the options for phase balancing in the existing networks and their costs are not well established. This may require a demonstration project that could build on much of the current innovation focused on measurement and monitoring of LV networks, and test emerging power electronics based technologies that may deliver tangible reduction in imbalance, in addition to providing power and/or voltage control. The benefits of reducing phase imbalance will not only be driven by the reduction in losses but several other operational benefits such as improved utilisation, better voltage regulation, longer life of assets, reduced radio interference etc. Assessing the overall benefits achievable through reducing imbalance is likely to require further economic study which is beyond the scope of this work.

In terms of managing imbalance when connecting new consumers, greater attention to choice of phase selection for connection of new services could provide a cost effective mitigation measure. In this context it is desirable to consider developing a set of comprehensive policies and procedures relating to the avoidance of further increases in imbalance, particularly when connecting new customers.

Recommendation 3: Further work is required to assess the extent of the imbalance problem and to test various solutions, which will not only reduce losses but deliver many other benefits of a well-balanced network. It may be appropriate to develop policies and working practices for avoiding excessive imbalance in future.

2.4 Impact of non-diversified loading in loss calculations

The case for not tapering LV feeders is further reinforced by the analysis of the impact of non-diversified load profiles that are particularly relevant for feeder sections supplying small number of consumers. To capture the impact on losses from load variations, five-second time power flow assessments have been carried out.

Figure 6 shows the load profile for an individual consumer modelled for 5 minutes. The erratic needle peaks in load behaviour are due to the operation of appliances such as central heating, kettles, washer-dryers, lighting and other devices that are used in the household. The 5 minute load model captures spikes up to 10kW whereas in the smoothed half-hourly profile the maximum load is 2.4kW.

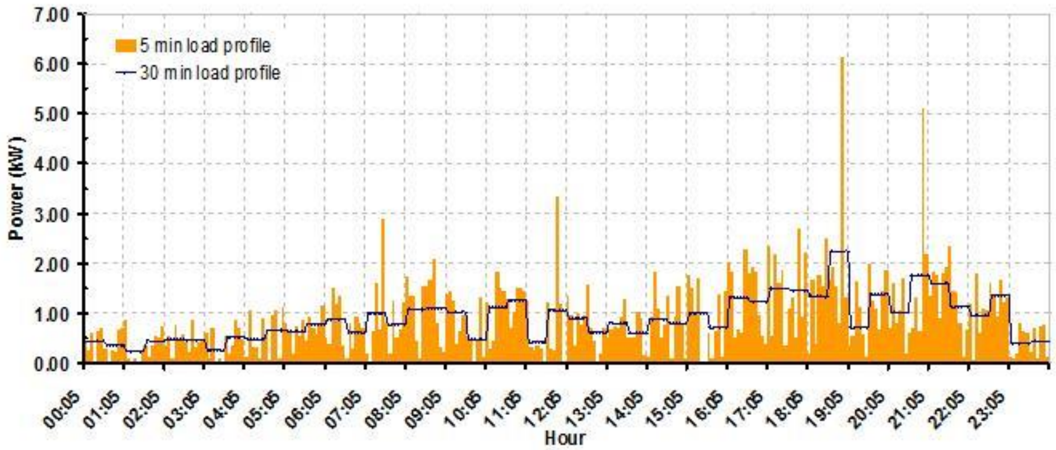


Figure 6: Modelled single consumer energy use over 24 hour period

The impact of diversity is presented in Figure 7 for 10 and 100 customers. Consequently the smooth, after-diversity load profile for a large group of consumers does not need to be sampled at a high rate in order to be accurately recorded. The load curve for hundreds of homes can be sampled at a 30 minute rate with little appreciable error. High sampling rates are needed only when studying flows, voltage and losses at the edges of the distribution networks.

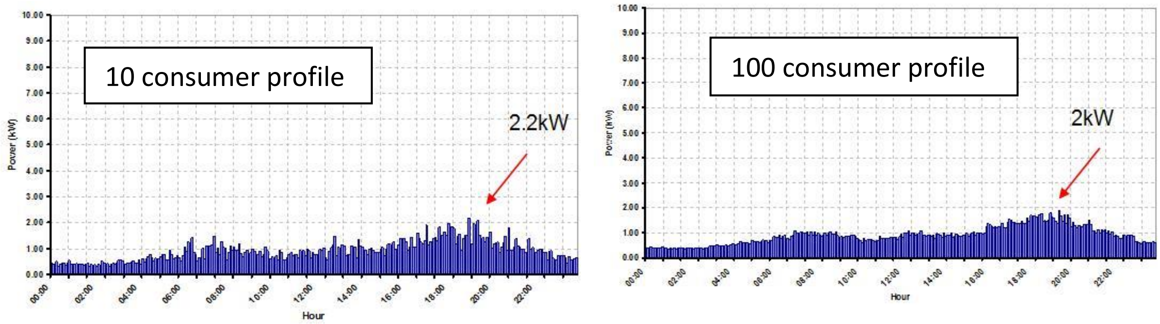


Figure 7: Diversified load profiles

The impact of diversity on network losses has been estimated from comparing two cases. In the first case, each individual consumer demand is represented by five-second profiles, while in the in the second case each consumer is represented through half-hourly demand (in this exercise 1000 daily load profiles are generated with five-second resolution as illustrated in Figure 8).

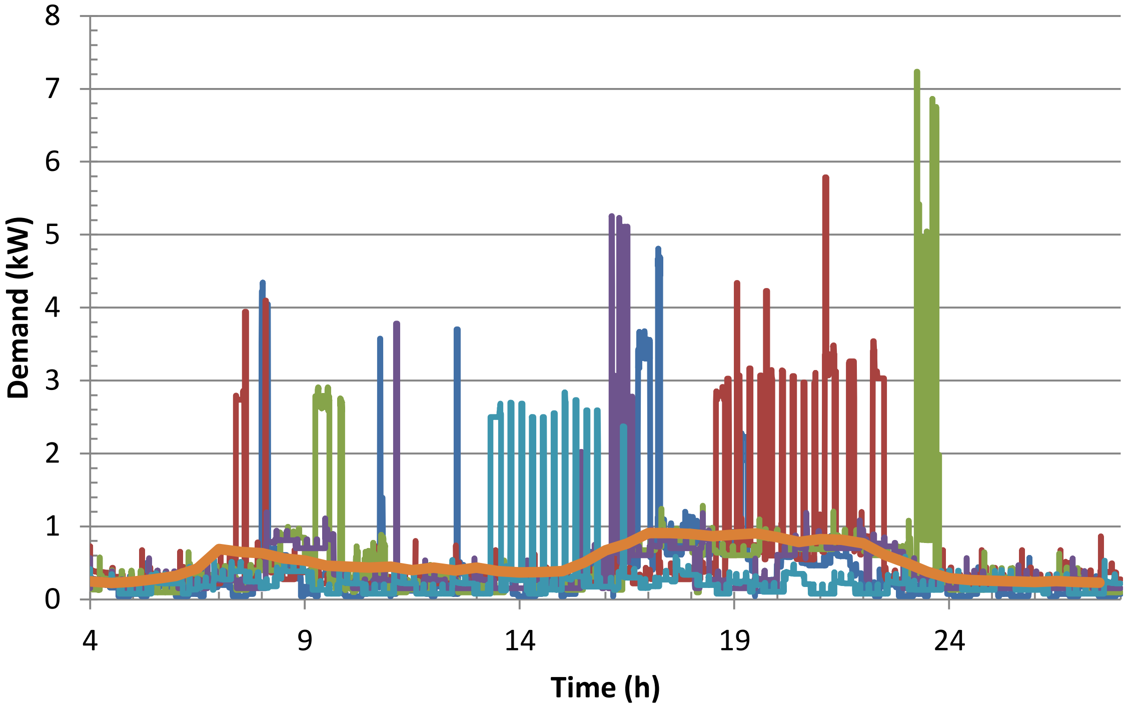


Figure 8: Non-diversified profile of households and average diversified profiles of many households.

The losses obtained in the first case are divided by the losses obtained in the second case for each network section, which is shown in Figure 9.

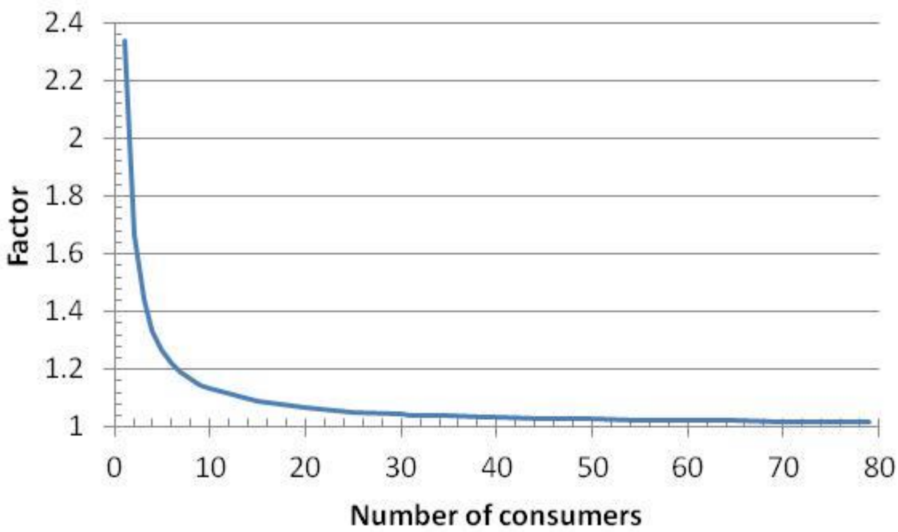


Figure 9: Modelled loss factor for diversified load profiles

The results indicate that calculated losses from a non-diversified load profile are 2.34 times higher than those less accurately calculated from diversified loadings. The degree of under-estimation of losses is materially significant and network designers should remain alert to the significant inaccuracy in evaluating losses at the edges of LV networks service cable when applying diversified profiles.

Using similar high-speed time-slicing, the losses in the LV mains network, after diversification, are 10% higher than would have been calculated using half-hourly data.

This clearly demonstrates that demand volatility at the edges of LV network including service cables, is the key driver for relatively higher losses in these parts of the network when compared with sections supplying larger number of consumers, which further reinforces the case of not tapering LV distribution networks.

Recommendation 4: The inaccuracy of loss calculation using half-hourly data at the edges of the LV network should be recognised when conducting network studies.

2.5 Impact of peak demand reduction on network losses

In this analysis we examine the benefits of reducing peak demand on network losses. This could be achieved through various forms of smartgrid technologies and corresponding active network management techniques including demand side activities, such as direct peak shaving, voltage control, network reconfiguration, peak pricing through time-of-use tariffs, etc. The results are summarised in Table 5, showing the impact of different levels of peak demand reduction (5%, 10% and 15%) on reduction in losses in semi-urban and semi-rural networks.

Table 5. Reduction in losses driven by peak demand reduction

Peak demand reduction (%)	Loss reduction for semi-urban network (%)	Loss reduction for semi-rural network (%)
5	1.3 – 2.2	0.6 - 1.1
10	2.5 – 3.6	1.3 – 2.6
15	4.6 – 6.6	3.9 – 6.5

It is important to note that the reduction in peak demand may be followed by load recovery, in which case peak reduction fundamentally represents demand re-distribution rather than demand curtailment. In this context, the ranges of loss reduction will depend on the amount and timing of demand that is recovered during off-peak periods (e.g. a lower recovery of demand gives a higher reduction in losses).

The potential benefits of reducing peak in terms of reduced losses have been estimated for a network supplied by a single distribution transformer as follows: for semi-urban networks the benefits range from £904 for a 5% reduction in peak demand (followed by full load recovery) and a low electricity cost, to £9,746 for a 15% reduction in peak demand (followed by limited load recovery) with a high electricity cost; for semi-rural these benefits range from £601 at 5% reduction for low cost of electricity to £13,320 for 15% reduction and high cost electricity.

Recommendation 5: As the benefits of peak demand reduction may be material, an assessment of the opportunities enabled by alternative smartgrid techniques to achieve this should be carried out.

2.6 Voltage control driven load reduction

Electricity demand and network loadings will be affected by network voltage. In most cases, by reducing voltage, demand and network losses will reduce, but the effect is highly dependent upon the nature of the demand and the characteristics of the power network. Our network model was applied to assess the impact of voltage regulation on network losses for semi-urban and semi-rural networks, as shown in Figure 10.

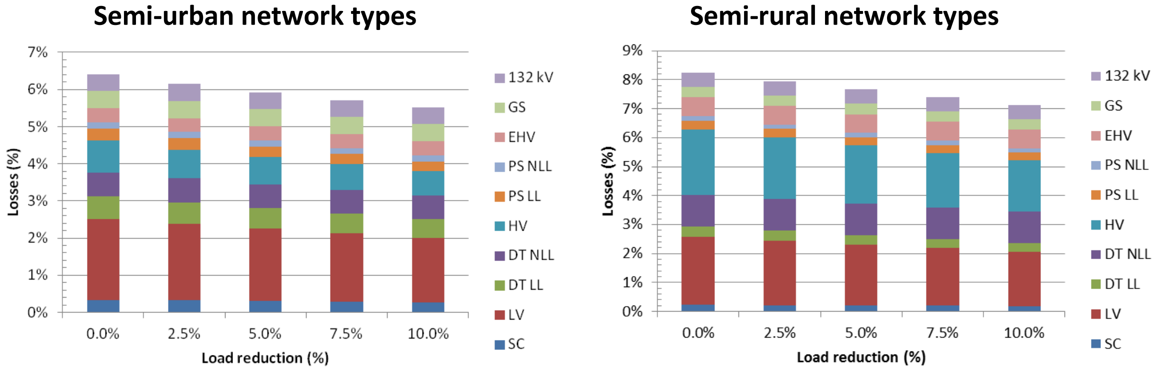


Figure 10: Impact of load reduction on network losses for semi-urban and semi-rural networks

As indicated in the summary of the results in Table 6, the impact of voltage reduction on losses is non-linear with a 5% reduction in energy giving a 9% reduction in losses for semi-urban network and a 13% reduction in losses for a semi-rural network although the biggest reduction for the semi-rural network occurs (mainly in the HV component) with the first 2.5% of energy reduction.

Table 6: Reduction in losses with energy supplied

Energy reduction (%)	Loss reduction for semi-urban network (%)	Loss reduction for semi-rural network (%)
2.5	4	4
5	8	7
7.5	11	10
10	14	13

This work gives a useful indication of the scale of loss reduction which may be realised and how that may differ between different types of network. The potential benefits of voltage control in terms of reduced losses have been estimated. These indicate that the benefit of voltage control, evaluated in the LV network supplied by a single distribution transformer, is highest in semi-urban networks, increasing from £2,900 with a 2.5% reduction in energy use with a low electricity cost to over £20,500 for a 10% reduction in energy use with a high electricity cost. The benefit for semi-rural section of LV network supplied by a single distribution transformer is about half, varying from £1,500 at 2.5% reduction and low cost electricity to £12,400 at 10% reduction with high cost electricity.

There are many practical issues to consider such as the impact of voltage regulation and the ability or otherwise to maintain customers' supply voltage within statutory limits. Also, the assumptions which have to be made regarding customer response to lower voltage over time affect the accuracy of this analysis.

This work focussed on including losses in LV design proposals and may assist in considering voltage control at distribution transformers or application of advanced in-line voltage regulators and consumer-end voltage control based energy efficiency technologies. Additional voltage control is being considered by DNOs in order to manage the uncertainty of new load and in particular with the recent increased penetration of PV generation.

Recommendation 6: As the benefits of active voltage control in LV distribution network may be significant, comprehensive assessment of the opportunities to further reduce network losses should be carried out.

2.7 Impact of enhancing network utilisation on network losses

Introduction of various smartgrid technologies and corresponding active network management techniques is aimed at enhancing network utilisation, reducing network costs and timescales for connecting new low carbon generation and demand technologies. Enhancing the ability of existing distribution networks to integrate new generation and demand through smartgrid concepts will in many cases lead to increased utilisation of the network and a consequent increase in losses. In other cases, losses, at least in terms of percentage of units distributed, may decrease. This is considered further as a policy issue in Section 5.3.

A previous study considered alternative active network management techniques to facilitate connection of a wind farm to the existing 33 kV network shown in Figure 11. The 33kV network is fed from a 132kV network (busbar 1) through a transformer fitted with an on-load tap changer (OLTC). Loads are connected to busbars 2, 3, 4 and 5. The load as busbar 2 represents the aggregated loads of the remaining part of the system. Embedded wind generation is connected at busbar 6, where power factor correction capacitors are also connected. In this case, voltage rise at the point of connection of the embedded wind generator is the key barrier that limits the amount of generation that can be connected to the existing network.

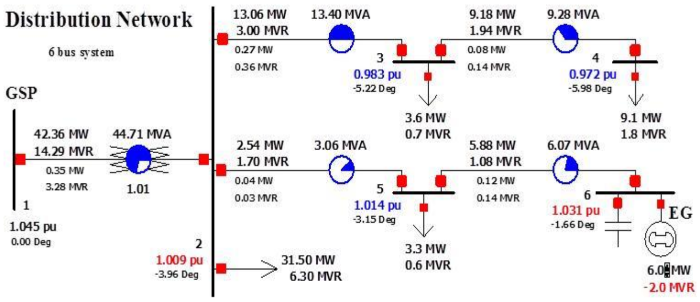


Figure 11: 33kV network model showing maximum loading conditions

The benefits of four active network management techniques in term of enhancing the ability of the network to accommodate increased penetration of wind generation are modelled: generation curtailment, power factor (PF) compensation, area-based OLTC voltage control, and in-line voltage regulators.

For each set of measures the wind generation capacity is increased from 4MW to 20MW in 2MW steps and the annual energy produced is calculated. The base case is provided by applying the standard limit to the increase in voltage at the connection point which would only allow 6MW of wind capacity to be connected. In Figure 12 the lighter bars represent the net energy generated in the course of one year, while the darker bars represent the curtailed energy.

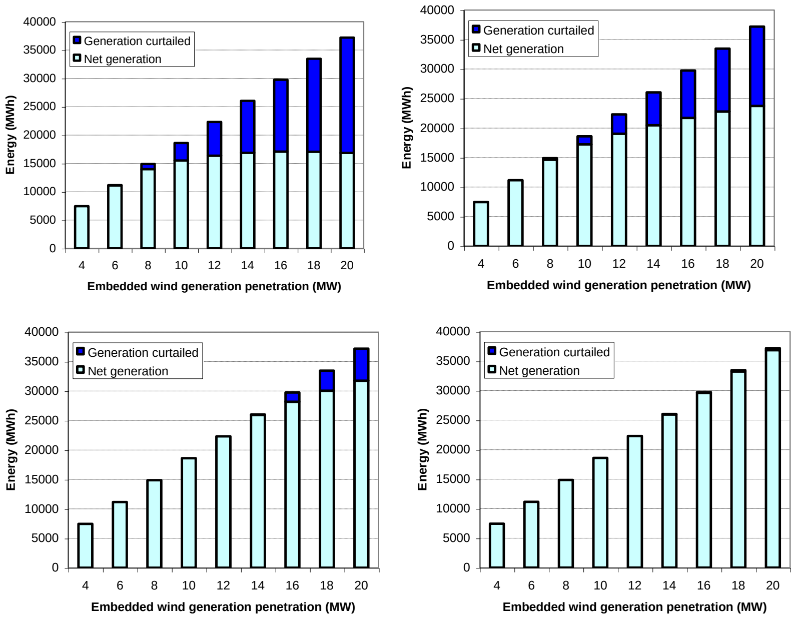


Figure 12: Benefits of four alternative ANM schemes: 0.98 PF, 0.95 PF, Area based OLTC, Area based OLTC with in line voltage regulation

In the first ANM scheme, generation curtailment and power factor compensation (power factor is 0.98) is applied at the wind farm. The OLTC transformer maintains a constant voltage at its terminals. The top left chart in Figure 12 shows the resultant *annual* energy produced and curtailed with installed capacity from 4 MW to 20 MW. Based on the passive management, the capacity of Distributed Generation (DG) allowed for connection is generally limited by the extreme conditions of minimum loading and maximum generation output. This condition only allows 6 MW of generation to be connected while connecting generation with higher power ratings will lead to increase in generation curtailment to manage the violation of voltage limits at the connection point.

Similarly in the second ANM scheme, generation curtailment and power factor compensation (power factor is 0.95) is applied at the wind farm. The OLTC transformer maintains a constant voltage at its terminals. The results are shown on top right chart in Figure 12. In this case, the net energy generated is increasing beyond 8 MW, as the energy curtailed for installations larger than 10–12 MW is significant. Comparing this case with the previous clearly shows the benefits of operating with lower power factors. In other words, a request to operate wind farms with unity power factor will limit the amount of generation that can be connected.

In the third ANM scheme, an area-based voltage control by OLTC is considered with the tap position optimised to minimise generation curtailment. Year round analysis shows that wind generation levels up to 14MW can be achieved with virtually no energy curtailed. This technique of voltage regulation will require a distribution management system with appropriate communication systems.

The final ANM scheme considered the minimising of generation curtailment by applying area-based voltage control by OLTC and in line voltage regulator. In this case, the control of voltage on feeders which supply load is separated from the control of voltage on the feeder to which the generator is connected by the application of a voltage regulator on the feeder connected to the wind farm. This allows an independent voltage regulation on feeders with loads by the OLTC, while the voltage regulator controls the voltage on the feeder with the wind farm. The modelling shows that this allows up to 20MW of generation capacity to be connected with almost no curtailment.

In summary, we observe that the least effective ANM scheme is generation curtailment and power factor compensation (around of 8MW of generation would be connected), while the most effective one would involve area based voltage control and the application of in-line voltage regulation (around 20MW of wind generation can be connected to the network).

Given the interest in this study, an analysis of losses has been carried out to illustrate how different active network management techniques used to connect a wind generator may affect losses as shown in Figure 13.

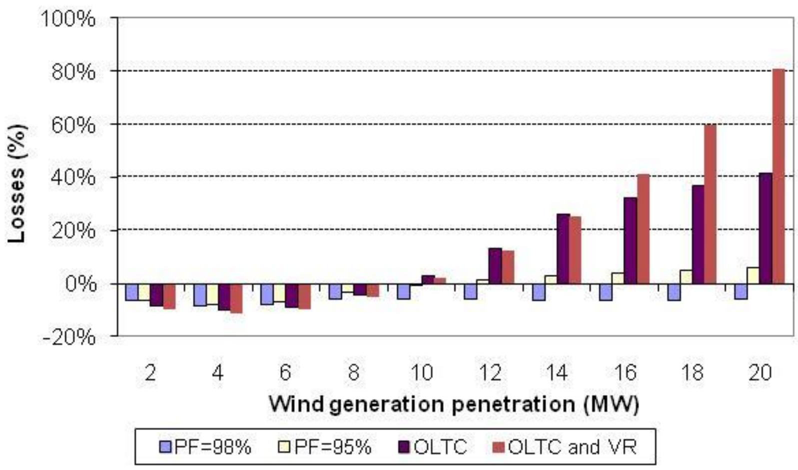


Figure 13: Impact of ANM schemes on network losses for various level of penetration of wind generation

We observe that the application of advanced active management techniques that would maximise the utilisation of existing networks may increase losses in the local network very significantly.

In terms of overall economics, the increase in losses may be efficient when "traded" against the facilitation of low-carbon generation connections and avoided network reinforcements. Nonetheless network loss increases may be also described as a decrease in energy efficiency and as such, undesirable.

Another study has demonstrated the impact of smart charging, employed to enhance the ability of existing networks to accommodate electric vehicles (EVs). As smart charging increases the utilisation of the network, losses will increase as shown in Figure 14.

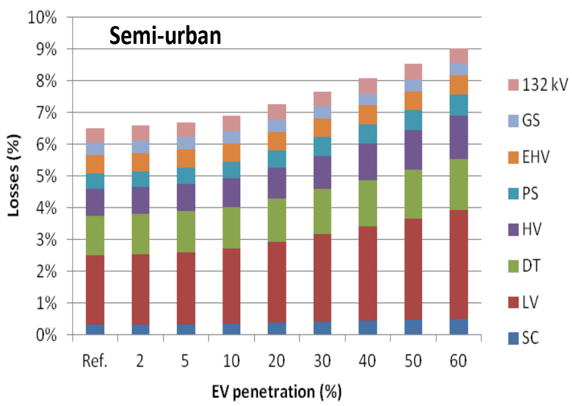


Figure 14: Impact of EV penetration on losses in semi-urban network; smart EV charging

We observe that with penetration of electric vehicles of about 50%, using smart charging to integrate electric vehicles within the existing network, the increase in losses will be more than 30%.

There is clearly a significant interaction between active network management techniques deployed to improve utilisation and avoid network reinforcement and the associated effect of increasing losses. This highlights the trend of that the application of ANM techniques to increase asset utilisation and avoid traditional network reinforcement, is more likely to lead to increase rather than decrease in distribution network losses. The scale of impact can be evaluated using appropriate modelling and assessment tools.

The current programme of smartgrid technology developments provides both “loss-favourable” technologies such as profile-flattening techniques[7] but also “loss-adverse” solutions such as dynamic line ratings and solutions which allow the inbuilt capacity for network resilience to be used for normal operating conditions with load-shedding in circumstances of network failure.

The critical policy matter in the context of this Study is that the options for investment should consider the long-term impact on network losses.

Recommendation 7: When considering active network management solutions and technologies to facilitate low-carbon connections, the impact on losses should be given full consideration.

2.8 Impact of increase of conductor temperature on losses

Conductor resistivity is dependent on conductor temperature. Hence losses are also dependent on conductor temperature. Temperate dependent resistivity has been modelled for various asset utilisations in order to assess the increase in losses with increasing temperature. As shown in Figure 15, the increase is between 0.4 and 1.4% for fully loaded underground cable with a range of heat exchange coefficients (HEC) of 10-30 W/m^{2}K. For a fully loaded overhead line it is about 2.2% for a heat exchange coefficient of air of 6 W/m^{2}K.

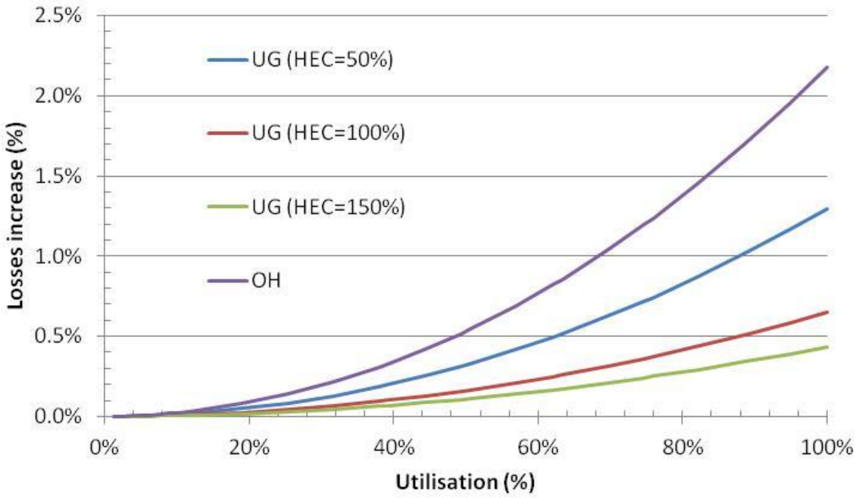


Figure 15: Impact of temperature on losses

It is in the assessment of losses in network analysis in which the temperature coefficient of resistance will be of relevance. In routine DNO design work, the assumptions of conductor temperature are not varied according to the conductor current. Furthermore, the loss calculations in network analysis

[7] Typically, this includes some of the Demand Side Response innovations and some of the current developments in electricity storage

tools do not compute the temperature of the conductor in relation to the load being carried. This could potentially lead to inaccuracies in loss calculations.

3 Loss inclusive network design

DNO network design policies have been driven by the basic requirements for reliability as defined in Engineering Recommendation P2, of which the current version is P2/6. DNO networks have been designed and built to meet all reasonable demands for safe and reliable distribution of power at an efficient cost, but without fully factoring-in the economics of losses. Essentially, this has meant that network design has been established to safely distribute electricity at lowest cost when operating at peak demand, rather than optimizing the network by economically factoring asset lifetime losses into the decision-making process.

The principle behind this Study is that the GB distribution networks should be designed with consideration of the economic value of losses and that there should now be a departure from the traditional approach of designing networks for safety and reliability at the lowest capital cost. It is proposed that the lowest cost in future should include the valuation of losses over the anticipated asset lifetime, which should be an input to the design requirement, not a consequence of how the network has been designed, as illustrated in Figure 16 showing the trade-off between asset and losses cost as a function of asset rating. In this example, and as may be expected, investment costs may be significantly greater than under the present regime.

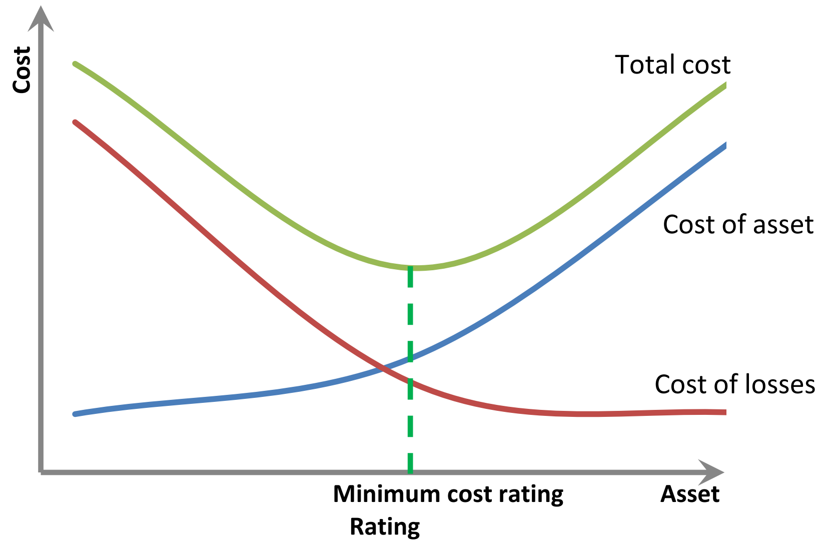


Figure 16: Impact of loss inclusive network design on asset costs

With an understanding of losses, the Study has then considered the economic justification for techniques which may be included as “loss inclusive network design”.

3.1 Modelling assumptions

In order to assess cost benefits, evaluation methods have been applied with the following inputs:

- Minimum and maximum energy costs at peak demand and low demand. Note that carbon prices have not been included in this analysis and therefore the benefits in avoided loss will be greater than calculated here. Also, costs and benefits in future years are held flat, taking no account of inflation in the NPV calculations;

- Costs of network equipment, covering underground cable and OH lines across different voltage levels; and
- Various capitalisation parameters, including the RIIO-ED1 guidelines of 3.5% discount rate over a period of up to 45 years.

Table 7 and Table 8 show the energy cost and the circuit costs respectively which we have assumed for the investment exercises in this Report. It is noted that these are indicative rather than market-related costs.

Table 7: Minimum and maximum energy costs

Demand type	Maximum cost (£/MWh)	Minimum cost (£/MWh)
Peak demand	80	40
Off-peak demand	20	10

Table 8: Circuit costs used in our studies

Name	Cost (£/MVA.km)
LV Cable	35,000
LV OHL	25,000
11 kV Cable	1,500
11 kV OHL	500
33 kV Cable	750
33 kV OHL	250

Note: LV – low voltage, OHL – overhead line.

In our related studies[8,9] supported by DNOs, rating driven (variable) and fixed cost of LV Al cables of £42/km.mm^2 and £6,680/km, respectively are used. Note that the fixed cost of circuits does not impact the choice of cross section area / rating (the same applies to the costs of cable installation that dominate the overall costs). For example, the rating related (variable) cost of LV Al 185 mm^2 cable is £43/km.mm^2 x 185mm^2 = £7770/km. On the other hand, by using the variable cost of LV cable of £35,000/MVA.km (in Table 8) we obtain very similar variable cost of this cable of £7,760/km.

The various parameters used in the loss inclusive investment exercises are shown in Table 9.

Table 9: Parameters for least cost network design

Scenario	Electricity Cost	Cost (£/MWh)	Discount Rate	Evaluation period (years)
1	High (peak period)	80	3.5%	45
	High (off peak period)	20		
2	High (peak period)	80	4.0%	20
	High (off peak period)	20		
3	High (peak period)	80	9.0%	20
	High (off peak period)	20		
4	Low (peak period)	40	3.5%	45
	Low (off peak period)	10		

[8] D. Pudjianto, P. Djapic, G. Strbac, Evaluating the impact of EDF Networks investment strategies on losses, Summary report for EdF, 2009

[9] S. Ćurčić, G. Strbac, X.-P. Zhang, Effect of losses in design of distribution circuits, IEE Proc.-Gener. Transm. Distrib., Vol. 148, No. 4, July 2001

Scenario	Electricity Cost	Cost (£/MWh)	Discount Rate	Evaluation period (years)
5	Low (peak period)	40	4.0%	20
	Low (off peak period)	10		
6	Low (peak period)	40	9.0%	20
	Low (off peak period)	10		

The annual cost of losses, factoring seasonal (k_s), temperature (k_t) and profile sampling (k_p), can be expressed as:

$$C_{loss,a}(£/km) = k_s k_t k_p 3 \frac{\rho_{50}(\Omega m)\,10^3(m/km)}{A(mm^2)10^{-6}(m^2/mm^2)} I_m^2(A) \sum_{t=1}^{T} d_t(h)\left(p_t(p.u.)\right)^2 \frac{c_t(£/MWh)}{10^6(W/MW)}$$

where

ρ_{50} is resistivity at 50 °C,

A represents cross sectional area,

d_t duration of period t,

p_t normalised power at period t,

c_t cost of energy at period t,

T is the number of characteristic periods per year i.e. 9 characteristic days represented by hourly profiles, 9 x 24 = 216,

maximum current is

$$I_m(A) = \frac{n P_1(kW)}{\sqrt{3} V(kV)\, p.f.}$$

where n is number of consumers, P_1 is peak demand of a single consumer, V is voltage and p.f. power factor (in line with earlier studies, power factor of 0.96 is assumed)

Net present value is

$$C_{loss} = NPV(dr(\%), \tau(years), C_{loss,a})$$

where *dr* is discount rate and τ is asset lifetime.

The total cost is then evaluated as the sum of the variable conductor cost and net present value of losses:

$$C = C_v + C_{loss}$$

Minimisation of the total cost will provide the least-cost peak utilisation factor:

$$\min_{\forall n}(C) \rightarrow u^{opt} = I_m(A)/I_r(A)$$

Given that load profiles of various types of consumers (e.g. domestic, small commercial consumers) connected to LV network are generally not recorded, we made use of established Imperial representative load profiles that have been already applied in a number of studies considering future LV network operation and design. The generic demand models use a small number of typical representative days and annual peak demand for each consumer type. Nine typical days are adopted to represent annual variation in load for domestic unrestricted, domestic economy 7, commercial and industrial consumer types, respectively. For this exercise we have chosen three temperature seasons (winter, summer and spring/autumn) and each of them are represented with the three typical days (working day, Saturday and Sunday). Holidays are classified as Saturdays or Sundays. An example of load profiles for diversified domestic consumer is presented in Figure 17 (for other customer types, i.e. domestic economy 7, commercial and industrial are presented in Appendix 2).

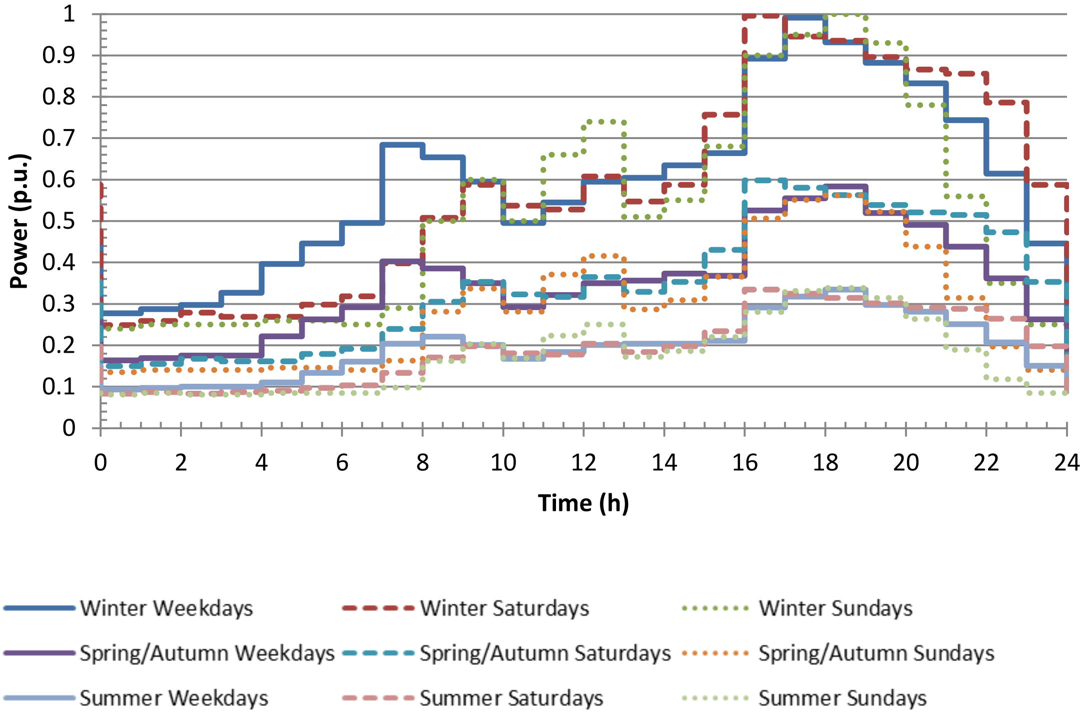


Figure 17: Characteristic daily profiles for diversified domestic consumers

Annual after diversity maximum demand (ADMD) for different consumer types are shown in Table 10.

Table 10: Number of characteristic days per year

Consumer type	ADMD (kW)
Domestic unrestricted	1
Domestic economy 7	2.5
Small non-domestic (commercial)	5
Medium non-domestic (commercial)	30
Large non-domestic (industrial)	100

The assumed number of characteristic days per year is shown in Table 11.

Table 11: Number of characteristic days per year

Season	Day type	Number of days
Winter	Weekdays	81
	Saturdays	19
	Sundays	20
Spring/Autumn	Weekdays	54
	Saturdays	10
	Sundays	13
Summer	Weekdays	116
	Saturdays	24
	Sundays	28
Total		**365**

Figure 18 shows the principle of generating consumers' mix of demand that is used for evaluation of network losses. The expected demand for a given hourly period is determined from the relevant hourly value chosen from the associated normalised characteristic daily profile for a given season and day type, considering all consumer types. An expected annual demand profile is then obtained by repeating process for all periods.

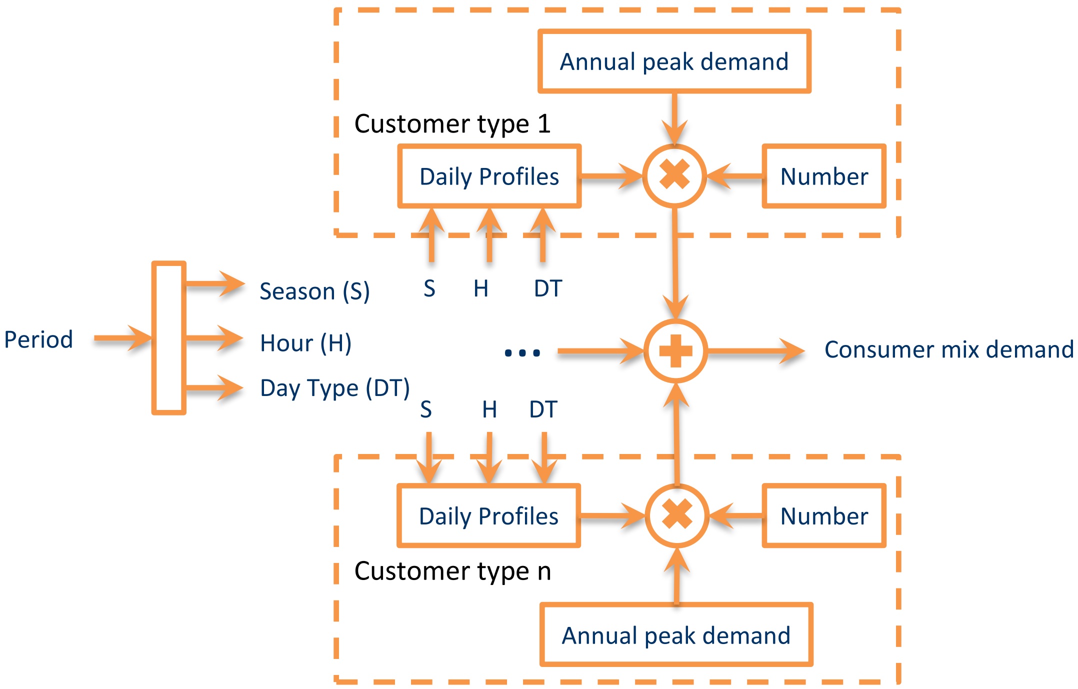


Figure 18: Evaluation of Consumer mix demand for a given hourly period in a time

The remainder of this section examines the opportunities for further reductions in losses by considering various networks' characteristics which may be changed by alternative design policies. The objectives are to achieve a "least cost network design" in place of the "peak load network design".

3.2 Optimal peak utilisation factors of distribution circuits

One of the most significant outcomes from the Study is the overall least-cost level of asset utilisation which would be justified if no other factors, such as practicality and affordability, were to be considered.

We defined peak utilisation factor as the peak demand divided by plant/equipment rating.

(a) Loss inclusive design of cables and overhead lines

The results in Table 12 show the outcome of the optimisation of the peak utilisation factors (economic maximum network loading as a percentage of rated capacity) for overhead and underground circuits operating at different voltage levels, for different electricity prices and discount rates. For example, if losses were the only consideration, an LV cable being sized according to the RIIO-ED1 capitalisation guidelines of 3.5% discount rate up to 45 years, would be operated at maximum demand no higher than 12-25% of its thermal rating. An HV overhead line would be matched to a maximum demand no higher than 8 -14% of its thermal rating.

Table 12: Least-cost maximum loading (%) for various electricity costs, discount rates and expected life of assets

Assets		High electricity cost			Low electricity cost		
		Discount rate					
		3.5%, 45 years	4%, 20 years	9%, 20 years	3.5%, 45 years	4%, 20 years	9%, 20 years
Cables	LV	12 - 25	16 – 32	20 – 39	18 - 35	23 – 45	28 – 55
	HV	14 - 27	18 – 35	21 – 43	19 - 39	25 – 50	30 – 60
	EHV	17 - 33	22 – 43	27 – 52	24 - 47	31 – 61	37 – 74
OH lines	LV	11 - 19	14 – 24	18 – 30	15 - 27	20 – 35	25 – 43
	HV	8 - 14	11 – 18	13 – 22	12 - 20	15 – 26	18 – 32
	EHV	10 - 18	13 – 22	16 – 28	14 - 25	18 – 32	22 – 39

The figures shown are the range of percentage maximum loading under different investment criteria and different assumptions of electricity cost. Note that the Ofgem guideline for forward pricing of sustainable electricity saved is £48.42/MWh with an additional avoided loss value based on carbon abatement. We note the figures of maximum network loading in Table 12 are conservative, and could be even lower, as the analysis did not included carbon prices and was based on relatively low energy prices of £45/MWh, particularly in the light of the recent announcement that the strike price for new nuclear would be £92.50/MWh.

We have also assessed the sensitivity of the optimal peak utilisation factors presented in Table 12, to an increase in rating driven (variable) cost of circuits, which is presented in Figure 19. As expected, an increase in rating driven cost of circuit for 50% will increase optimal peak utilisation factor, e.g. for LV cables, the peak utilisation factors will increase from the range of 12-25% to 16-30%. However, even the increase in circuit cost for 50% peak utilisation factors of circuits are low and losses, rather than peak demand, will be critical for the design.

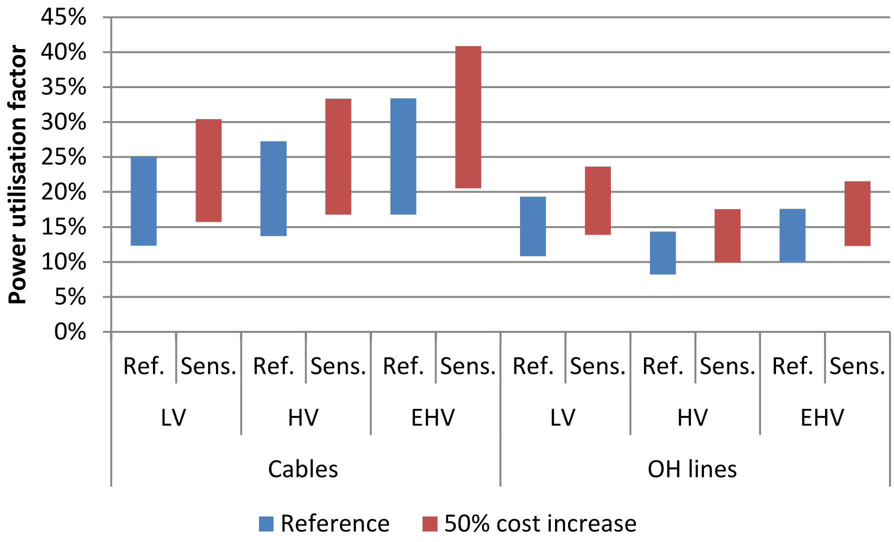


Figure 19: Sensitivity of power utilisation factor

In summary, the results indicate that under various scenarios, low levels of network peak loading can be justified in order to economically optimise the network design. This is essentially re-defining the economic rating of plant and equipment based upon the chosen parameters for valuation of losses. From examination of DNO's Engineering Specifications (quoted in Engineering Recommendation G81 Appendices for each DNO), we identify that DNOs are currently specifying larger conductors than are required to carry peak load, and we also note the differences in approach being taken between DNOs.

There will be many practical reasons for limiting the physical size of conductors e.g. strength limitations of supports for overhead lines, or complications in connection of large cables to smaller cables, but the use of conductors which are larger than the current least-cost solution is economically justified when including losses in the design considerations.

In view of the inconsistencies in sizing network conductors and Ofgem's latest views of loss management, it may be appropriate to fundamentally review network design standards to specify economic ratings that would be consistent with the UK energy and carbon reduction policy.

Impact of least-cost design on losses in some representative networks is shown in Figure 20 to Figure 23. For comparison the network design based on ER P2/6 is also shown. We observe that least cost network design is characterised by significantly lower losses. Note that the differences in losses between peak demand based and least cost network designs is largest in rural networks, and then the difference reduces in semi-rural and semi urban networks, and being the smallest in urban networks, which is predominantly driven by the network lengths associated with the corresponding areas.

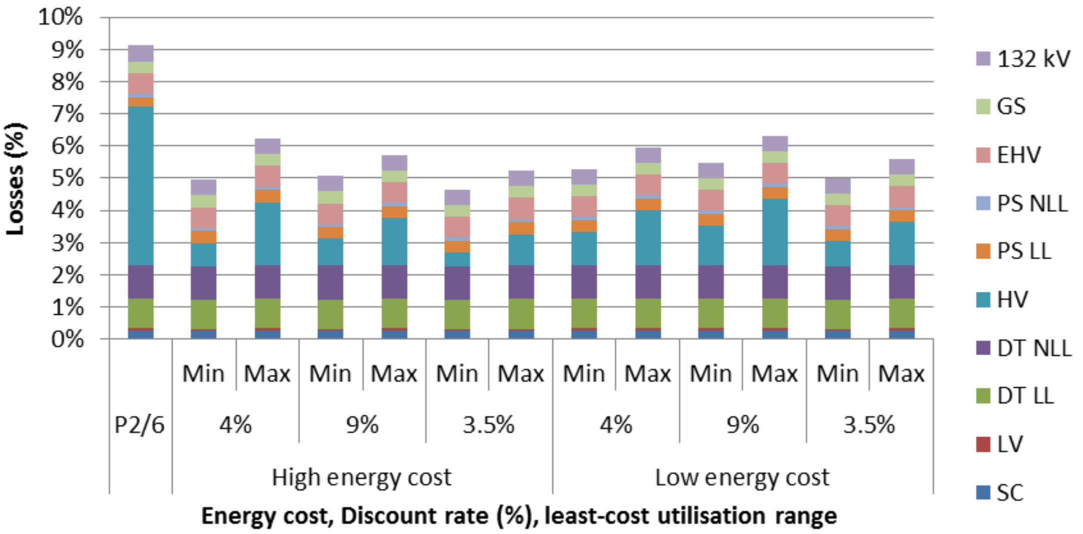


Figure 20: Least-cost network design for rural networks

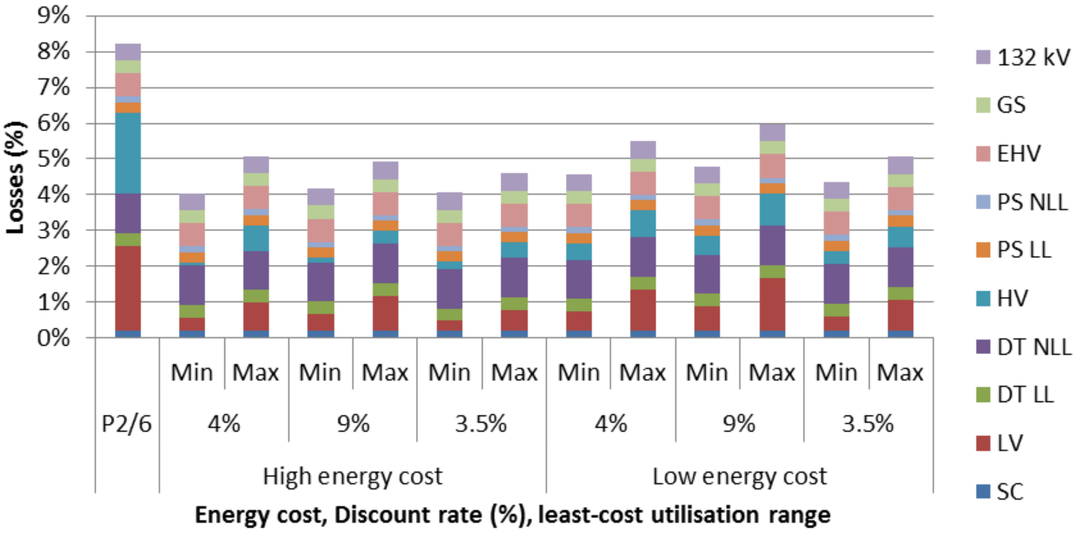


Figure 21: Least cost network design for semi-rural networks

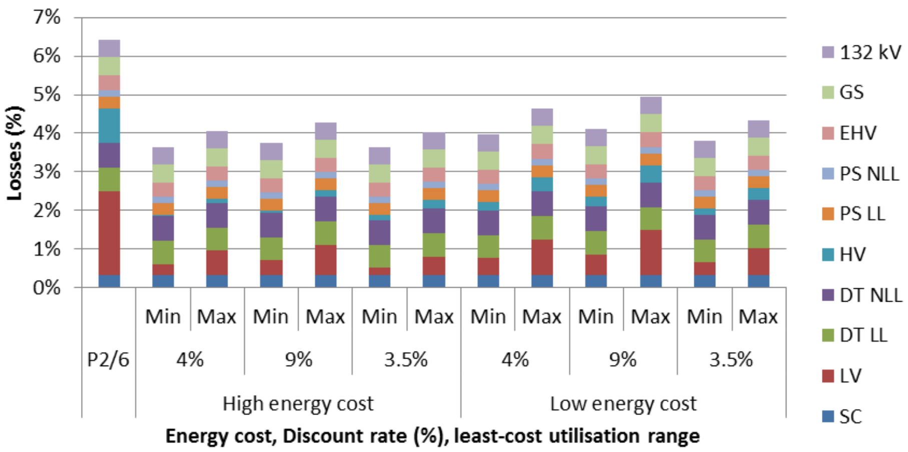


Figure 22: Least cost network design for semi-urban networks

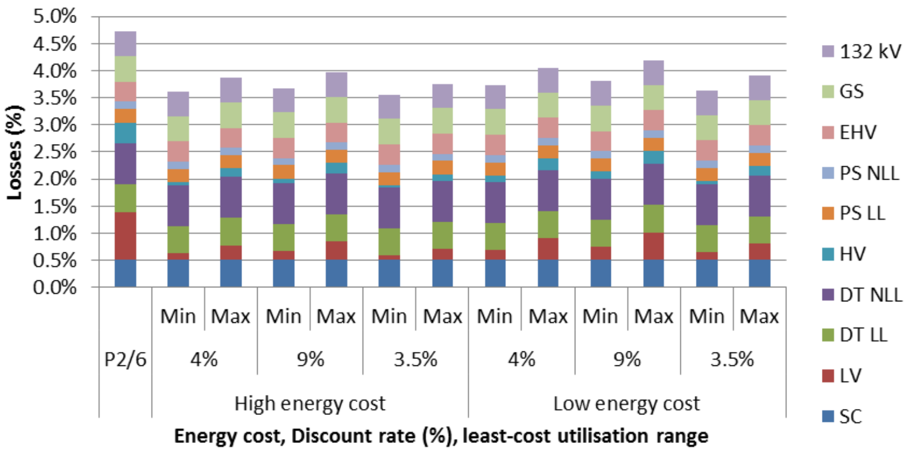


Figure 23: Least cost network design for urban networks

The results obtained are summarised in Table 13 and we observe that network losses reduce significantly for least cost network design. We stress that these loss reductions are conservative and could be higher, as the loss-inclusive network design was based on relatively low energy prices with carbon prices excluded.

Table 13: Network losses in different network designs

Typical Network	Peak-design	Loss-inclusive design
Rural	6.0% - 9.1%	4.9% - 5.4%
Semi-rural	5.8% - 8.2%	4.0% - 4.5%
Semi-urban	4.9% - 6.4%	3.6% - 4.0%
Urban	4.2% - 4.9%	3.6% - 3.8%
GB level	**5.8% - 6.6%**	**4.0% - 4.4%**

Additional modelling of different network types was carried out to compare the effect on network losses of a range of power factors for peak-driven and loss-inclusive network design. Figure 24 and Figure 25 provide a summary of this analysis for a semi-rural and a semi-urban type network. As the power factor improves from 0.8 to unity, the results indicate a reduction in losses of about 1.9% for the peak-driven network and around 0.5% (from a much lower starting point) for the loss-inclusive network design in semi-rural network. Similarly, improving power factor would reduce losses of 1.3% for peak-driven and 0.5% for loss-inclusive design in semi-urban networks.

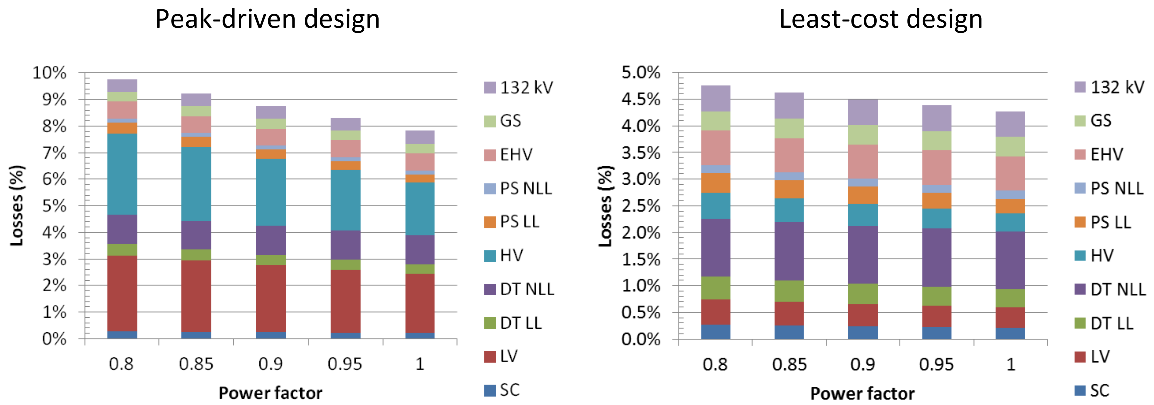


Figure 24: Variation of losses with PF in semi-rural network types

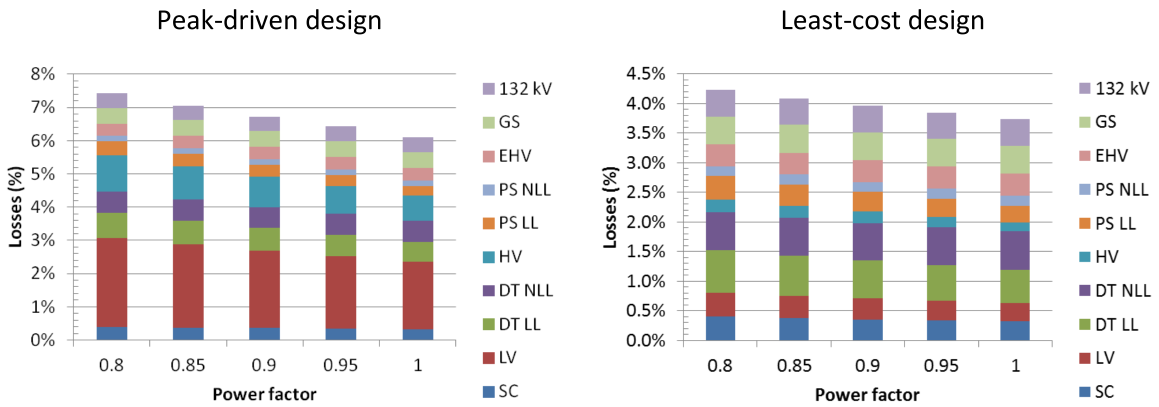


Figure 25: Variation of losses with PF in semi-urban network types

Table 14 gives the estimates the benefits of installing power factor equipment for peak-driven design and for loss-inclusive design. We observe that the benefits of improving power factor in loss-inclusive network design are between 2-3 times lower when compared with peak-driven designs. This demonstrates significant robustness of loss-inclusive design with respect of possible deterioration in power factor.

Table 14: Benefits (£/KVAr) of improving power factor to unity for different network types

Power factor	P2/6 design				Loss inclusive design			
	Urban	S-urban	S-rural	Rural	Urban	S-urban	S-rural	Rural
0.95 → 1	13 – 31	24 – 59	36 – 88	43 – 106	8 - 19	8 - 21	8 - 20	11 - 28
0.9 → 1	40 – 99	73 – 179	105 – 259	126 – 310	24 - 59	27 - 65	26 - 63	35 - 86
0.85 → 1	76 – 188	137 – 337	197 – 485	247 – 608	46 - 113	51 - 125	49 - 121	66 - 163
0.8 → 1	120 – 296	214 – 529	309 – 761	–	73 - 179	80 - 197	77 - 190	105 - 258

We have also investigated the impact of changes in load profiles, due to penetration of low carbon demand technologies such as Electric Vehicles (EV) and Heat Pumps (HP), operating under a full smartgrid paradigm (as shown in Figure 26). Using DECC 2030 scenario and assuming full demand controllability aimed at reducing peak demand, the developed loss inclusive network design was carried out to determine the optimal peak utilisation factors of distribution network circuits.

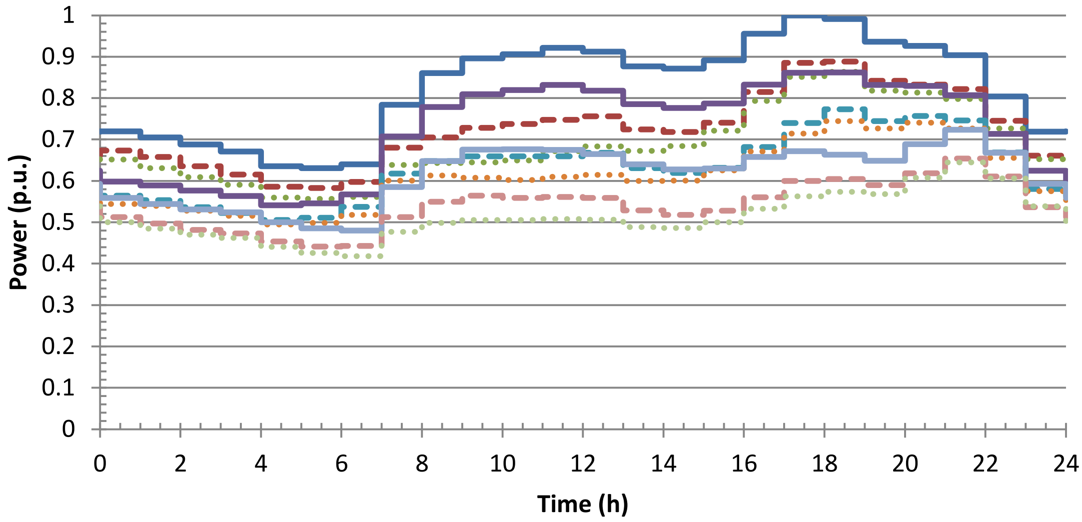


Figure 26: Normalised characteristic day profiles for 2030

As shown in Table 15, we observe that the minimisation of network peak would lead to further reduction in network peak utilisation factors due to much flatter load profiles (after diversity peak demand increases from 1 kW in the reference case to 2.7 kW in 2030).

Table 15: Optimal peak utilisation for present load diagrams and 2030 demand profiles

Assets		Reference demand profile	2030 demand profile
Cables	LV	12 - 25	7 - 14
	HV	14 - 27	8 - 17
	EHV	17 - 33	10 - 20
OH lines	LV	11 - 19	6 - 10
	HV	8 - 14	5 - 9
	EHV	10 - 18	6 - 11

This demonstrates the robustness of the key findings of this analysis that loss inclusive network design would essentially re-define the economic rating of distribution networks.

(b) Loss inclusive design of distribution transformers

Table 16 and Table 17 show the outcome of the analysis of economic network loading of distribution transformers, with losses assessed using two cases (a) discount rate of 3.5% over 45 years and (b) discount rate of 9% over 20 years, respectively, assuming high energy costs.

It is interesting to observe that transformer capital costs are similar to the cost of losses (discount rate of 3.5% over 45 years) and that the optimal utilisation of transformers may be between 60% and 100%. Note that the minimum overall costs, in cases of peak demand being 500kVA and 630kVA would be achieved by installing an 800kVA transformer.

Table 16: Least-cost Distribution Transformer for case discount rate of 3.5% over 45 years

Rating (kVA)	CAPEX (£)	Peak demand (kVA)	Cost of losses (£)			Total cost (£)	Peak Utilisation Factor
			Load losses	No-load losses	Total		
315	13,137	315	9,254	6,984	16,238	**29,375**	100%
500	14,168		5,249	10,277	15,526	29,694	63%
630	15,020		3,928	12,272	16,200	31,220	50%
500	14,168	500	13,173	10,277	23,450	37,618	100%
630	15,020		9,858	12,272	22,130	37,150	79%
800	15,199		6,373	12,711	19,084	34,283	63%
500	14,168	630	21,066	10,277	31,342	45,510	126%
630	15,020		15,764	12,272	28,036	43,056	100%
800	15,199		10,191	12,711	22,902	38,101	79%

As expected, the cost of losses in the case of discount rate of 3.5% over 45 years is significantly higher than in the case based on a discount rate of 9% and the time horizon of 20 years. However, in this particular case the optimal transformer peak utilisation in both cases are the same.

Table 17: Least-cost Distribution Transformer; discount rate 9% over 20 years and high energy cost

Rating (kVA)	CAPEX (£)	Peak demand (kVA)	Cost of losses (£)			Total cost (£)	Peak Utilisation Factor
			Load losses	No-load losses	Total		
315	13,137	315	3,755	2,834	6,589	19,726	100%
500	14,168		2,130	4,170	6,300	20,468	63%
630	15,020		1,594	4,980	6,574	21,594	50%
500	14,168	500	5,346	4,170	9,516	23,684	100%
630	15,020		4,000	4,980	8,980	24,000	79%
800	15,199		2,586	5,158	7,744	**22,943**	63%
500	14,168	630	8,548	4,170	12,719	26,887	126%
630	15,020		6,397	4,980	11,377	26,397	100%
800	15,199		4,136	5,158	9,294	**24,493**	79%

This clearly demonstrates the impact that losses may also have in choosing ratings of transformers. As shown below in the case of low-loss transformers, the optimal utilisation of transformers will be 100%.

Recommendation 8: There is a clear case for fundamentally reviewing cable and overhead line ratings to ensure that future loss costing has been included in the economic rating calculation. This could be based on Ofgem's loss investment guidelines or on loss-inclusive network design standards.

3.3 Low-loss transformers

Further analysis was carried out to assess the benefits of low-loss transformers including the business case of applying low-loss transformers in future network developments. Table 18 shows the losses in the present design typically used in GB and low-loss transformers, including dry and liquid-immersed low-loss technologies which correspond to those required for Tier 2 of the proposed EU Standard. We observe that low-loss transformers improve significantly both the load loss and no-load loss performance. We also note that the losses in a significant proportion of existing distribution transformers are higher than losses in the present designs.

Table 18: Losses in standard and low-loss transformers

Rating (kVA)	Present Transformers		Low loss (dry type)		Low loss (liquid-immersed)	
	Load loss (W)	No load loss (W)	Load loss (W)	No load loss (W)	Load loss (W)	No load loss (W)
315	4800	700	3877	496	2800	288
500	6860	1030	5630	722	3900	408
630	8150	1230	7100	880	4600	480

The analysis in this study was based on a cost-benefit analysis of choosing low-loss distribution transformers compared with lower-cost higher loss transformers.

Table 19 presents the additional investment cost in low-loss transformers over and above the conventional high-loss designs.

The analysis was carried out for a with either discount rates of 9% for an evaluation over 20 years or a discount rate of 3.5% over a period of 45 years. The results indicated that the additional expenditure available for the installation of low-loss units instead of standard units is significant and that in many cases it will be economic to install the more expensive low-loss transformers (the lower costs correspond to the 9% rate over 20 years. It is also expected that the costs of low-loss units will fall as the units are manufactured in greater quantities.

Table 19: Breakeven additional cost of low-loss transformers over classical type

Rating (kVA)	Breakeven additional cost of low loss transformers (£)	
	Dry type	Liquid-immersed
315	2,452 – 3,651	5,117 – 7,618
500	3,492 – 5,199	7,637 – 11,369
630	3,547 – 5,281	9,217 – 13,721

This is an area of policy in which one would expect best practice to prevail throughout GB. In this context it would desirable to develop GB wide clear policy in terms of discount rates, investment periods and energy and carbon-abatement costs that are consistent with the GB energy and carbon policy, and this is an important area for dialogue between industry, regulator and government.

The analysis also considered the effect on the network losses of in case of the application of low-loss transformers. The results in Figure 27 compare losses in case of a standard transformer (Business As Usual - BAU) with the case of the application of low loss transformers for various transformer densities in a range of typical network types. It can be seen that in all cases the use of low-loss transformers reduces network losses, particularly in more urban networks.

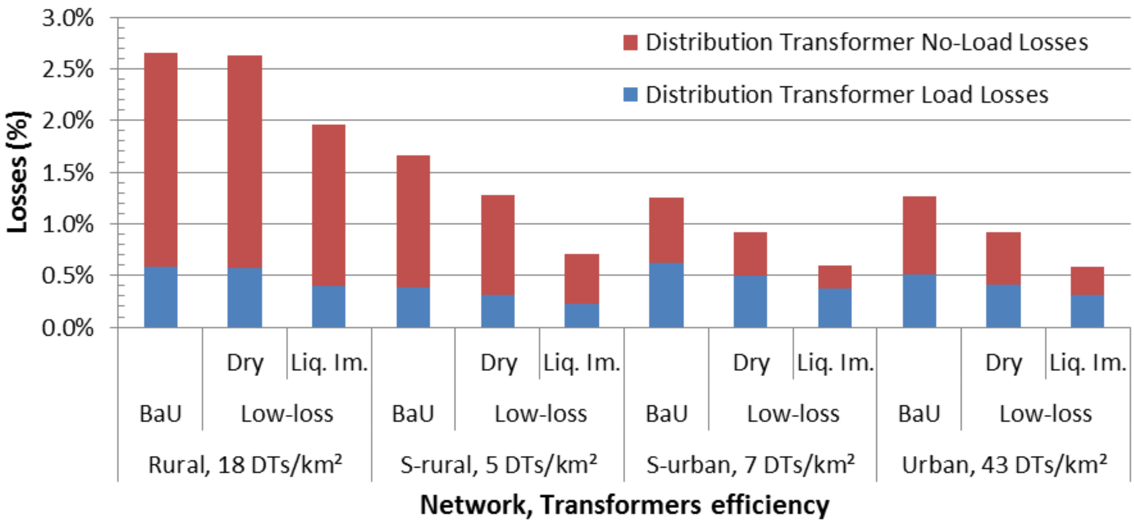


Figure 27: Comparison of overall transformer losses for standard and low-loss transformers

Finally, Table 20 presents the comparison of network loss performance in different network types when different network design strategies are applied, including the application of low-loss transformers. This clearly indicates that the losses in future distribution networks should be reduced by nearly 50% when compared with the present situation. Note that these loss reductions are in fact conservative, as the analysis did not include carbon prices and was based relatively low energy prices.

Table 20: Network losses in different network designs including the application of low-loss transformers

Typical Network	P2 design	Loss-inclusive design		
		Transformer type		
		Standard	Low-loss (dry)	Low-loss (liquid immersed)
Rural	6.0% - 9.1%	4.9% - 5.4%	4.8% - 5.4%	4.3% - 4.8%
Semi-rural	5.8% - 8.2%	4.0% - 4.5%	3.6% - 4.1%	3.2% - 3.6%
Semi-urban	4.9% - 6.4%	3.6% - 4.0%	3.3% - 3.7%	3.0% - 3.3%
Urban	4.2% - 4.9%	3.6% - 3.8%	3.2% - 3.4%	2.9% - 3.1%
GB level	**5.8% - 6.6%**	**4.0% - 4.4%**	**3.7% - 4.1%**	**3.3% - 3.7%**

Recommendation 9: The transformer loss calculations indicate that the benefits of investing in low-loss transformers may be significant and this should be considered further to establish or otherwise the low-loss transformer business case in line with UK energy and carbon policy.

3.4 Early replacement of assets

Analysis was carried out to assess the business case for loss-driven early replacement of assets i.e. if consideration of losses may justify asset replacement ahead of need and in advance of them becoming overloaded or unreliable. We note that the phrase "ahead of need" has often been used in networks policy discussions but this has invariably been in the context of the need for capacity, safety, reliability and in some cases environmental issues e.g. pollution, but not losses.

This work shows that early replacement of transformers may potentially be justified and we note that some DNOs have included such a programme in their Business Plans. Table 21 shows the ranges of breakeven transformer replacement costs at which it would be economically efficient to replace 20-years old high-loss transformers with low-loss designs.

Table 21: Break-even cost for early transformer replacement; the ranges shown correspond to different discount rates

Rating (kVA)	Breakeven transformer replacement cost (£)	
	Dry type	Liquid-immersed
315	4,538 – 6,756	7,203 – 10,723
500	6,504 – 9,683	10,649 – 15,854
630	7,149 – 10,643	12,818 – 19,083

Note that these breakeven replacement cost are conservative and could be significantly higher, as the analysis did not include carbon prices and was based on relatively low energy prices of £45/MWh, particularly in the light of the recent announcements that the strike price for new nuclear would be £92.50/MWh.

The analysis in the Study, based on our assumed costs and loss performance of old and new transformers, supports such decisions. We understand from one DNO that the scale of early replacement being conducted is not constrained by a lack of economic justification for this work, but the practical resource limits of how much replacement work can be physically achieved in the period of the Business Plan.

On the other hand, our analysis shows that early replacement of cables is not economic, bearing in mind the cost of excavation and re-instatement in addition to the cable purchase and laying costs. This is illustrated on an example of a 400m LV underground cable 95 mm^2 , with 5, 10, 15 or 20 years of useful life remaining. We test whether it is economically viable to replace it now with 300 mm^2. The results are shown in Table 22. It can be seen that postponing cable installation is preferred. Therefore, the reduction in losses alone is not a driver for an early cable replacement.

Table 22: Comparison of net present values for various year of cable upgrade

Useful life left (years)	Condition based replacement			Early Replacement		
	Investment	Losses	Total	Investment	Losses	Total
5	33,140	928	34,068	39,360	644	40,004
10	27,903	1,168	29,071			
15	23,494	1,369	24,863			
20	19,781	1,539	21,320			

Recommendation 10: In future losses may drive early asset replacement of transformers when economically efficient. If early replacement programmes are economically justified and capable of being funded, appropriate resources would need to be made available to facilitate delivery of such programmes.

3.5 Transformer density

Our earlier analysis indicated that increasing the density of secondary distribution substations in feasible cases may enhance the ability of LV distribution networks to cost effectively integrate low carbon generation and demand technologies. In the Study we describe the scenario of strategically increasing the density of HV/LV transformers on the network to reduce the length of LV feeders and hence the network losses.

Figure 28 and Figure 29 presents the results from the analysis carried out in semi-rural and semi-urban types of network, showing breakdown of losses. In both cases significant reduction in variable losses may be achieved, although fixed losses will increase given that number of distribution transformers installed increases.

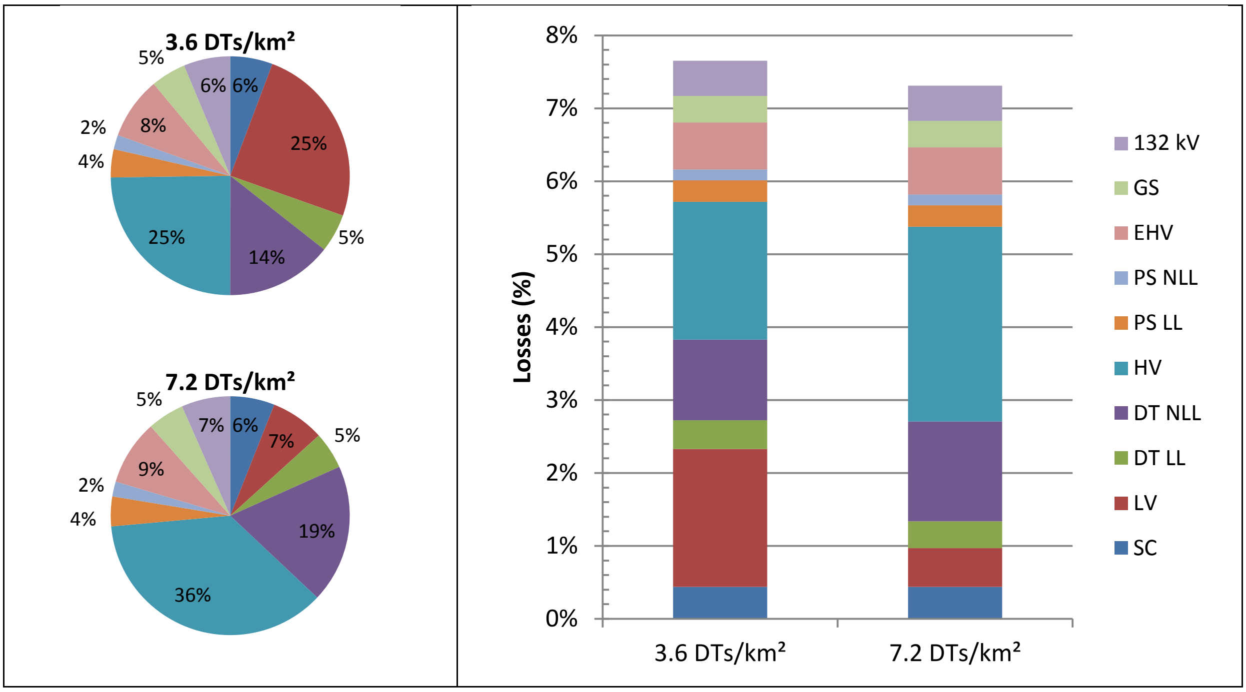


Figure 28: Impact of distribution transformers density on losses in a semi-rural type network

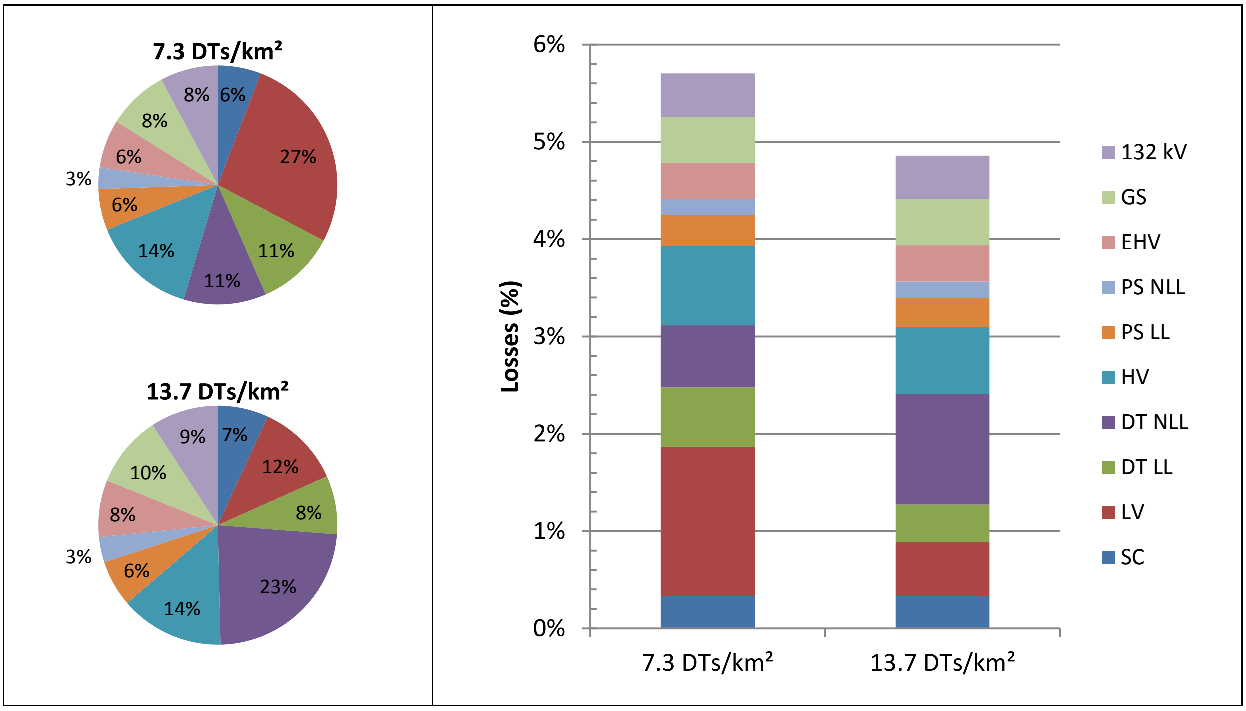
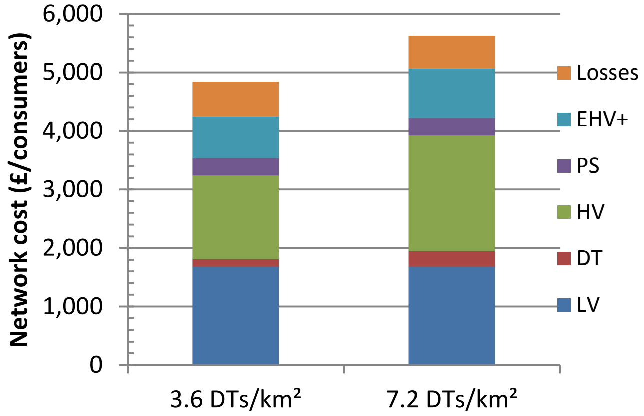


Figure 29: Impact of distribution transformers density on losses in a semi-urban type network

We observe that this may lead to a 10-20% reduction in overall network losses. However, the option to introduce additional secondary substations may be compared with other means of reinforcement such as laying new LV cables or replacing existing LV cables with larger ones. In those cases where LV network design changes are required – usually to accommodate new buildings or for reinforcement, then the LV design work can take losses into account when making the choice whether to reinforce the LV network or include additional substations.

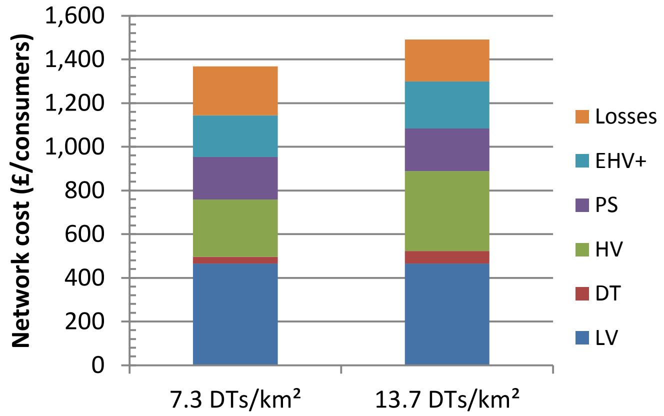
Our analysis demonstrated that distribution network reinforcement costs, driven by the uptake of low carbon technologies (EVs and HPs), is dominated by LV network reinforcement. A network replacement strategy that involves inserting additional distribution transformers could be very cost effective when compared with reinforcing LV underground network[10]. In stark contrast to this, in a case of *green-field* network development, the analysis shows that the network design with higher density of distribution transformers would be less cost effective as shown in Figure 30 and Figure 31, due to increased costs of HV and LV circuits although losses would be reduced.

[10] "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", Report by Centre for Sustainable Electricity and Distributed Generation, Imperial College, ENA, March 2010.



Distribution transformer density (1/km²)	Cost (£/consumer)		
	Assets	**Losses**	**Total**
3.6	**4,247**	**590**	**4,838**
7.2	**5,065**	**564**	**5,629**

Figure 30: Impact of distribution transformers density on network cost in semi-rural type networks



Distribution transformer density (1/km²)	Cost (£/consumer)		
	Assets	**Losses**	**Total**
7	**1,143**	225	**1,368**
14	1,300	**191**	1,491

Figure 31: Impact of distribution transformers density on network cost in semi-urban type networks

There may be practical factors that prevent the solutions that involve inserting of distribution transformers:

- the LV cable configuration does not allow sufficient LV feeders to be looped into or diverted into a new distribution substation;
- additional substation sites are unavailable; or
- the HV network is not suitably configured to accept additional substations.

Recommendation 11: Network designers may consider the option of installing additional distribution transformers to minimise LV network reinforcement cost and reduce network losses

3.6 Rationalising HV and EHV voltage levels

The design voltage levels chosen by network operators many decades' ago are potentially sub-optimal to deliver today's power levels and to support future requirements which may include increased level of demand and distributed generation. Network companies have developed long-term strategies for progressive changes to network voltages, driven largely by optimising the investment costs to meet the required levels of network utilisation. For example, many of the historical 6.6kV networks in GB have been replaced or uprated to 11kV over the past 40 to 50 years.

In some parts of GB distribution networks, especially in areas of high load density, direct transformation has been the preferred means of electricity distribution, e.g. 132/11kV. As network demands increase and reduced losses become more desirable, there is the potential for greater application of direct transformation. More recently, ESB has replaced large sections of their 10kV system with plant and equipment operating at 20kV in order to accommodate increased wind generation.[11] This has achieved an increase in network capacity and reduced network losses by 75% for about a 5% increase in cost.

In the context of the transition to a low-carbon economy, it is appropriate to consider if the present network design and voltage levels are optimal for the future and examine more fundamental changes in network design in order to facilitate cost-effective integration of low-carbon technologies such as heat pumps, electric vehicle charging points and distributed generation[12]. The Study has included an assessment of the impact on losses of selecting alternative voltage levels for various network types. A typical outcome in urban networks, as shown in Figure 32, indicates a sizeable reduction in losses which can be achieved on EHV and HV networks.

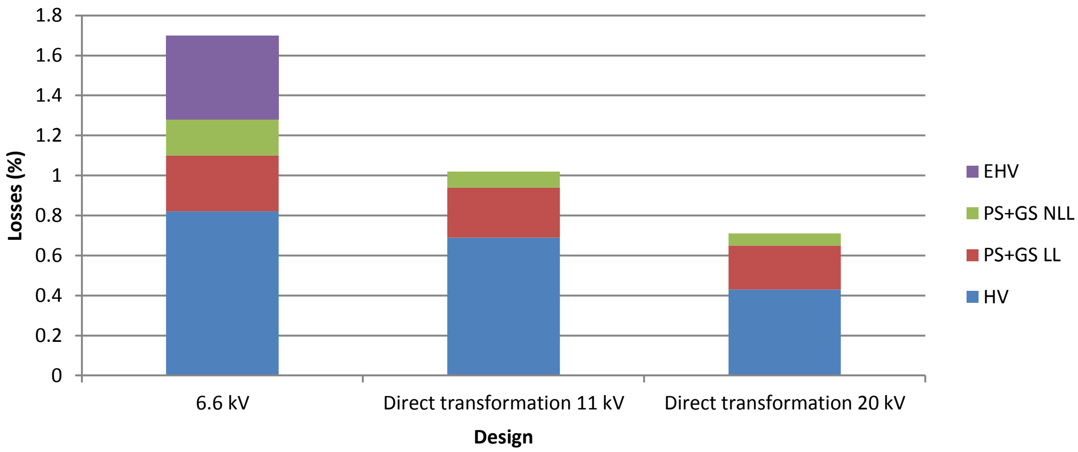


Figure 32: Losses in distribution systems with various voltage levels; HV – high voltage, PS – primary substation, GS – grid substation, LL – load losses, NLL – no-load losses, EHV – extra high voltage (33 kV)

We have also undertaken more detailed assessments of voltage rationalisation in GB typical networks. Illustrative examples of a semi-urban network and a semi-rural network are presented in Figure 33 and Figure 34, respectively, showing breakdown of losses (left) and the overall network cost (right) in four and three voltage level network designs.

11 http://www.seai.ie/Renewables/Wind_Energy/Regional_Wind_Workshops/Delivering_a_21st_century_electricity_infrastructure_ESB_Networks.pdf

12 Some DNOs have experienced a very significant increase in connection of distributed generation which is already re-characterising some parts of their networks.

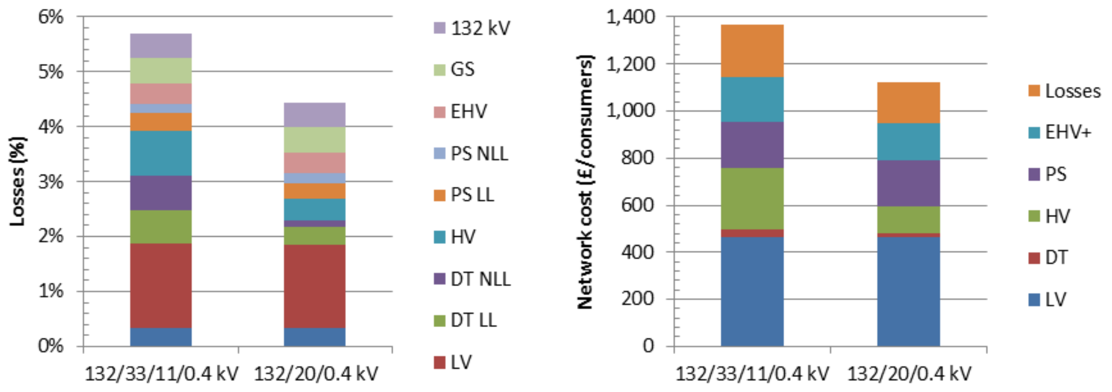


Figure 33: Losses in distribution systems with various voltage levels; LV – low voltage, DT – distribution transformer, HV – high voltage, PS – primary substation, EHV – extra high voltage (33 kV), GS – grid substation, 132 kV – grid network, LL – load losses, NLL – no-load losses

In case of semi-urban network, the overall losses are about 22% lower and total cost about 18% lower in direct transformation designs. Similar trends are observed in semi-rural networks, with direct transformation designs delivering reduction in losses of 22% and total cost about 12%.

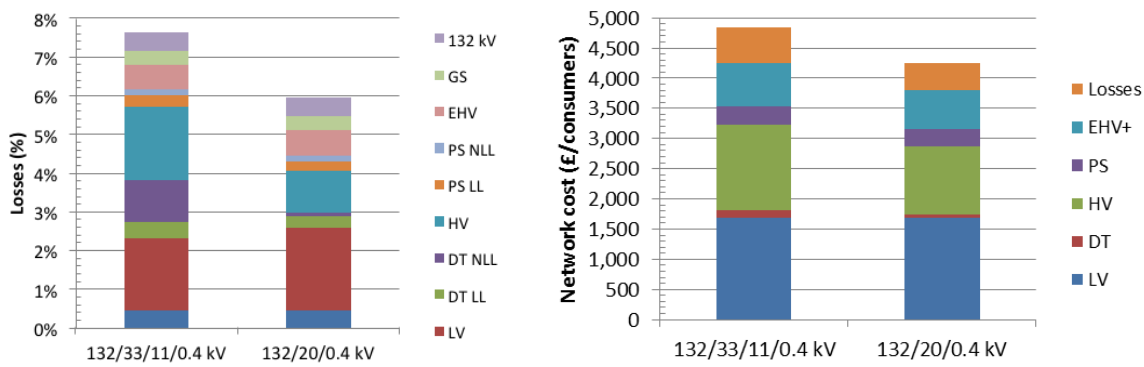


Figure 34: Comparison of losses for four and three voltage level designs of semi-rural type networks

Clearly, a major strategic long-term decision is required to design networks to alternative voltage levels. This will not be taken lightly, nor will it be made based solely on losses. However, the Study illustrates that by applying the principle of loss-inclusive design, the business case will be different when making decisions such as installing 20kV network or specifying more EHV/HV direct transformation.

The analysis provides a useful input to long-term thinking on network voltages and provides an example of how losses evaluations may be incorporated into the optimal choice of voltage for future networks.

Recommendation 12: In the light of future developments, particularly in relation to the integration of low carbon demand and generation technologies, it may be appropriate to reconsider long-term distribution network design. This may take a strategic view of future voltage levels and include consideration of losses in the decision-making.

3.7 Cable tapering

In GB, there has been a longstanding tradition of designing LV networks with reducing conductor sizes at greater distances along the feeder from the distribution substation. Compared with a non-tapered approach, this has enabled lower costs of construction, but has reduced network operational flexibility and has generated higher losses than would be the case with the same cable sizing along the feeder.

The impact of tapering on losses has been assessed on a 400m long tapered network, with cable reducing in size from 300mm^2 to 185mm^2 and 95mm^2 with loads which are uniformly distributed, linearly increasing and linearly decreasing as shown in Figure 35.

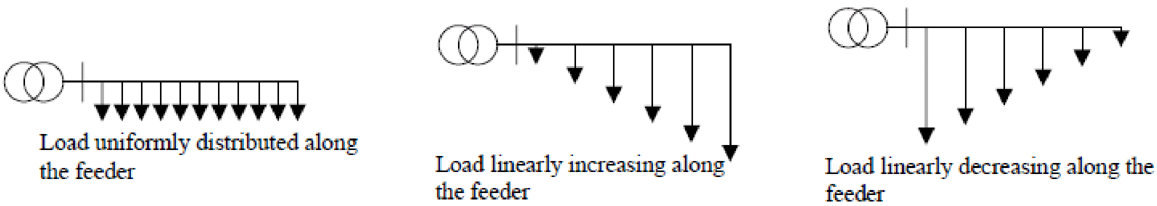


Figure 35: Load profiles assessed for the impact of cable tapering

Figure 36 shows example of the distribution feeder with peak current along the feeder versus distance from the distribution transformer. The analysis is illustrated on an example in which N_F = 50 customers are uniformly distributed along a feeder of 400m length. The before and after diversity peak demand of a single customer is 10kW and 1.2 kW, given the assumed coincidence factor (CF) of 0.1 and the power factor (PF) of 0.96. The maximum feeder demand (I_F) is 205A.

This analysis takes into account that the diversity depends on the number of consumers and the following expression

$$I_S = \frac{\left(1 + \frac{1/CF - 1}{\sqrt{N_S}}\right) \cdot N_S \cdot ADMD}{\sqrt{3} \cdot V \cdot PF}$$

is used to estimate the current through each cable section (I_S) which supply N_S customers, where V is voltage.

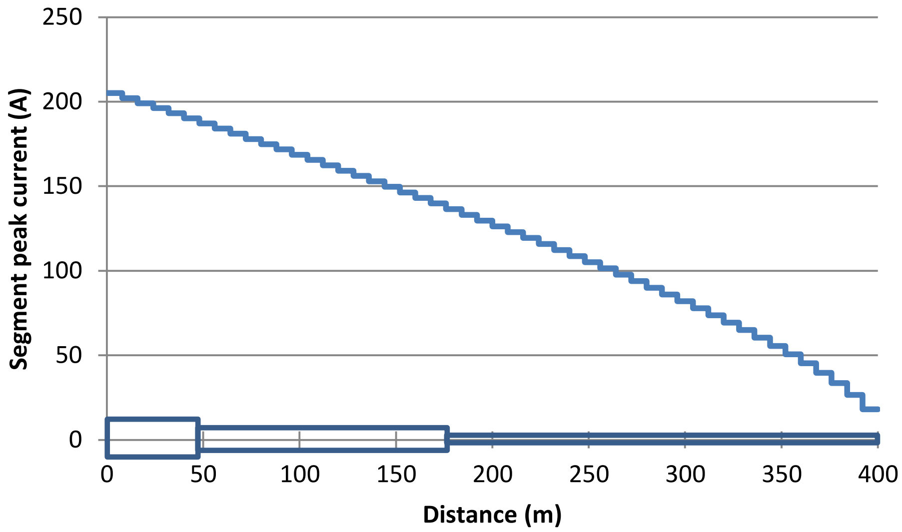


Figure 36: Distribution of peak currents (not necessarily occurring at the same time) along a feeder of 400 m which supplies 50 customers uniformly distributed along the feeder

This is compared with a non-tapered solution based on 300 mm^2 cable. The impact of tapering on losses, with three assumptions of load distribution, is shown in Table 23.

Table 23: Losses increase due to conductor tapering

Load distribution	Losses increase due to tapering
Linearly decreasing	36%
Uniformly distributed	57%
Linearly increasing	69%

A hypothetical set of tapered and un-tapered networks has been analysed to estimate the overall least-cost solution which takes losses into account. It is demonstrated that, whilst the tapered network may be of least cost, the cost differences are marginal and the case for un-tapered network may be very strong especially when other valuable features such as flexibility, standardisation, "future-proofness" and LV network reconfiguration are considered.

It is unlikely that a reduction in losses on their own will drive the policy on tapering. There are more significant issues such as volt drop and future network flexibility which affect the decision-making. However, we note that some DNOs do not apply tapering in their LV design for interconnected LV networks. A loss-inclusive approach to network design creates further bias of policy towards not tapering. The uncertainty of demand of electric vehicles and future retrofit of micro-generation would further justify a non- tapering policy, as being a prudent and relatively low-cost means of developing the flexibility required within the LV network to support the low-carbon economy. In order to reach a universal view in GB of not tapering, further analysis may be required of the instances in which tapering has been a limiting factor on the options available to the network designer when accommodating new load or microgeneration.

Recommendation 13: In order to reduce losses and provide future flexibility within LV networks, LV tapering policy may be re-examined.

3.8 New materials, plant and equipment for loss-inclusive network design

From both the technical analyses of network losses and the economic analyses of cost/benefits of loss mitigation, we conclude that much can be done to move towards energy efficient distribution networks, in which network loss is managed at its economic level. We also conclude that this can be achieved using conventional plant and equipment in addition to the new smartgrid and ANM solutions emerging from recent developments within various network innovation funding arrangements.

However, it is concluded that new forms of transformer designs and new conductor materials for more cost-effective solutions are not readily apparent and are unlikely to feature in network design for many years to come. Perhaps the most relevant development is an interesting trial of superconducting cable in Essen, Germany. In this project, which was justified on grounds of avoiding substations in a very congested part of the city, a 1km high-voltage cable connecting two transformer substations in the Essen area is being replaced with a superconducting three-phase, concentric 10 kV cable with capacity of 40 MW. More details can be found in Appendix 3.

3.9 Support requirements for loss-inclusive analysis and design

During our studies we held various discussions with systems providers, other consultants and DNO personnel on the suitability of network modelling and analysis tools. We considered IPSA, DINIS, Powerfactory and WinDebut and came to some general conclusions:

- Modern power network modelling and analysis tools are functionally rich and can readily analyse losses. The limitations on how engineers may be supported in loss analysis have not been the computing technology and algorithms but the lack of data entry into the systems and possibly the lack of priority being ascribed to loss management under current policy. For example, we identified a situation where Windebut was being used extensively for LV network design in which the loss valuation was set at the default value and had not been reviewed to take account of the DNO’s latest policy on valuation;
- To adapt the technologies to improve the presentation of losses including highlighting “hotspots” is relatively simple. In most systems we understand that changes may be made to identify and highlight losses on user-friendly displays for less than £0.5m;
- Systems can be developed and data can be acquired, validated and managed according to whatever requirements are set for effective loss management;
- The further development of the tools to provide more accurate loss calculations will be required in order to achieve loss-inclusive network design. In particular there will be requirement for analysis under multiple time-slicing;
- Present tools do not readily support optimisation of the alternative active network management techniques particularly those that involve time-coupled network optimisation such as smart charging of EV, or demand side response, and therefore assessing the impact of smartgrid technologies on annual losses may be very time consuming;
- The existing commercial tools can support network design, but do not automatically carry out cost-benefit analysis through balancing cost of investment and annual operating costs across multi-year time horizons;
- There are several alternative modelling tools designed for strategic network planning that consider losses, such as Imperial College’s Load Related Expenditure model which was used to inform ED1 business planning or the Strategic System Investment Model that considers investment in primary and smart technologies across multi-year planning time horizons.

For loss-inclusive network design to be embraced by GB DNOs such that all investments take account of the latest approach to capitalising the value of loss avoidance, then network design tools should be refined to support design engineers. The changes to systems and processes should not only deal with the technical requirements but should also be seen as part of a process of inculcating a change in priorities such that energy efficiency may become more significant in the overall design than has been the case in the past.

Recommendation 14: A review of DNOs' network modelling and analysis tools and capabilities may be required to support design engineers in applying new policies and processes relating to loss-inclusive network design.

4 Valuing heat generated by network loss

Distribution network losses in the UK account for about 6% of final electricity consumption, while at the same time significant efforts are being undertaken to decarbonise the UK heating sector in line with the national carbon reduction targets.[13] Part of this heating demand could be potentially met through the recovery of low-grade waste heat from electrical losses in distribution networks. Capturing and using the heat generated by network losses at locations where this heat could be efficiently delivered to customers could improve the overall energy efficiency of electricity distribution. This concept may be implemented as a retrofit solution, or may be engineered into the overall network design when new equipment is required. In this context, this section presents the research and analysis conducted aimed at evaluating the potential for using the heat generated by electrical losses in distribution networks[14].

Losses in distribution networks are mainly generated in transformers, underground cables and overhead lines. Given the obvious difficulties in harvesting heat from overhead lines, our study has focused on transformers and underground cables. Although most electrical losses occur in the low-voltage networks, their harvesting will be difficult given their wide geographic dispersion. Greater concentrations of losses are found, for example, in 132/33 kV or 33/11 kV transformers and the more likely success in economically harvesting heat lies within these higher voltage networks, which is where we have focussed our attention.

Heat generated from the distribution network assets is generally low-grade (< 50 °C) and it is hence uneconomic to transport it across large distances. Heat recovered from cables and transformers is therefore most likely to be more useful in buildings near to major substations. In case of space heating and cooling, heat pump systems appear to be the most promising technology to utilise the recovered low-grade heat, as the resulting increase in temperature at which heat is exchanged significantly improves their operational efficiency i.e. the Coefficient of Performance (COP).

As with many cases of heat recovery, there is usually a mismatch between the temporal variations of heat generation and demand, which would reduce the overall effectiveness of the heat recovery schemes. This will be the case especially if the recovered heat is only used for building heating rather than for hot water and/or cooling. To some extent this mismatch may be mitigated by heat storage and this is also considered as part of our investigation.

In this Study we consider the past experience of harvesting and using heat recovered from distribution network losses and the potential value of heat from transformers. We have developed models for assessing the feasibility and potential economic benefits of the use of recovered heat from transformers with heat pump technology using a set of models and life cost methods.

4.1 Previous experiences

Our review of recent projects addressing heat recovery from distribution transformer losses covers the relevant activities both in the UK and internationally.

The Tate Modern at Bankside in London is developing a low-energy extension which will use heat recovery and ground source heat pumps.[15] This scheme will use recovered heat from six adjacent

[13] Heat Strategy Team, "The Future of Heating: A strategic framework for low carbon heat in the UK", Department of Energy and Climate Change, March 2012. Available at: https://www.gov.uk/government/publications/the-future-of-heating-a-strategic-framework-for-low-carbon-heat.

[14] Although technical solutions for reducing network losses are well understood, at the current rate of network investment it will take decades before the upgrades leading to lower losses improve the loss profile across the network. Therefore it may be concluded that a significant amount of electrical losses will be present for many years. Whatever the level of loss on the network, be it economic or uneconomic, there is opportunity to improve energy efficiency by recovering and using the heat generated by electrical losses in network assets.

[15] http://www.maxfordham.com/projects/transforming-tate-modern/

UKPN transformers in the old Switch House, with the output of approximately 1 MW of heat. The hot water is initially used directly for heating, which is supplemented by heat from a heat pump using the low-temperature return water as a source. The scheme also has air-cooled heat exchangers when the Tate heat demand is insufficient to provide complete cooling. The capital cost of the heat recovery system has been provided by UKPN as part of the Innovation Funding Initiative and the initial estimates of the heat recovered (7,000 MWh/annum) will give a 4 year payback for the installation.

Islington Council has started the Phase 2 of their Bunhill Energy Centre project[16] and aim to include the recovery of waste urban heat discharged in the Islington Borough. This includes the heat generated by losses at a nearby UKPN substation, as well as waste heat from the underground railway. Funding has been secured from the Council, Bunhill Ward and the EU CELSIUS research project (managed by the GLA in London) to extend the heat network installed in Phase 1, and provide additional heat production capacity for connected buildings.

Rook Services[17] have installed RegenairHeat©, their non-intrusive heat recovery system, at National Grid's Hurst 400/132 kV substation with a further four projects under development and the potential to roll out installations for all of National Grid's substation offices, subject to successful feasibility surveys. The RegenairHeat© system installed at Hurst substation provides space heating for the offices at the substation site. The non-intrusive system extracts the heat from two transformer noise enclosures via two dry air coolers using a brine circuit. The brine is fed into a heat pump which upgrades the operating temperature and supplies low pressure hot water to the office radiators, replacing electric panel heaters. Results so far demonstrate that the system is outperforming initial estimates, while heat pump data indicate that a greater amount of useful heat is made available than originally expected. This "heat bonus" appears to be the heat recovered from the cables in the shared cable troughs. Capital costs for the Hurst installation and other National Grid estimates indicate the 'typical' installation costs at about £125k for future projects, resulting in a payback of just over seven years on energy costs alone. A detailed case study is provided in Appendix 4. Being the UK market leader in the installation of non-intrusive systems, Rook Services have expressed interest in also working on DNO projects.

Outside the UK, Vattenfall appears to be a market leader in recovering heat from transformers and is systematically rolling out heat recovery solutions at its substations in Sweden to supply office heating. Other less intensive activities identified so far have been initiated in Finland, Switzerland and Ireland (the latter had to be abandoned due to recession. However, a more detailed examination of Vattenfall's installations is likely to prove helpful for future investigations on this topic.

Recommendation 15: There is opportunity for considerable further learning in Europe and also from National Grid. It would be beneficial to share experiences of waste heat recovery installations among DNOs.

4.2 Potential for recovering heat from transformers

There are a number of different transformer cooling systems currently in use. These vary in complexity and in their effectiveness of meeting the primary objective of cooling the transformer. Technical features of different cooling options also determine the potential for extracting heat generated by losses, as indicated in Table 24.

Table 24: Potential to extract useful heat from different transformer cooling systems

[16] http://www.islington.gov.uk/services/parks-environment/sustainability/sus_energy/Pages/decentralisedenergy.aspx
[17] Source: Jason Garside, Commercial Manager, Rook Services Ltd, http://rookservices.co.uk

Cooling method	Potential	Comment
Oil Natural Air Natural (ONAN)	Low	This is the simplest type of cooling, used in many smaller transformers which are usually freestanding and from which it would be difficult to harvest heat. It is also used as the first stage of a typical substation transformer.
Oil Natural Air Forced (ONAF)	Medium	This type of cooling is normally used in a staged operation in conjunction with Oil Forced.
Oil Forced Air Forced (OFAF)	Medium	This is the final stage of a typical substation transformer which cascades from ONAN to OFAF as the cooling requirement increases. As the oil/air heat exchanger is in the open air, there is limited opportunity to harvest the heat except from within the transformer building.
Oil Forced Water Forced (OFWF)	High	This type of transformer currently offers the most opportunity for heat recovery and is used in several schemes. This system offers a high degree of control for heat recovery.
Oil Directed Air Forced (ODAF)	Medium	These are mainly used for high load industrial applications where minimising plant size is important and there is probably limited opportunity to harvest the heat in these situations.
Oil Directed Water Forced (ODWF)	High	

The OFWF transformer cooling system is the preferred starting point for the implementation of heat recovery of losses in new transformers as most of the generated heat is captured by the cooling water of the oil-water cooler, and water is a very suitable medium for transporting heat to a distant load. In addition, OFWF cooling also reduces the transformer size and this is particularly attractive in urban areas where space limitation is an important constraint when upgrading old or developing new substations. This is why the modelling work has focused on OFWF-cooled transformers.

Additional advantages of OFWF transformers over natural circulation cooling for heat recovery include:

- Opportunity to pump and store water into tanks
- Possibility to reheat water with boilers, heat pumps or electric heaters
- Better heat recovery control

Forced cooling systems are likely to provide a larger quantity of heat at higher temperatures but will require some form of back-up system to cool transformers in the event of a system component failure (e.g. the water pump). OFWF transformers are well-suited to heat recovery although they may require major piping systems which may be most cost-effective for new installations.

4.3 Methodology for assessing the economic feasibility of heat recovery from transformers

In order to assess the economic viability of waste heat recovery schemes from primary distribution transformers, we have developed a modelling framework that simulates the operation of the main assets involved and their interaction in the heat recovery process. The assessment of the economic performance of heat recovery has been carried out by comparing alternative space heating designs under different scenarios. The economic feasibility of various heating options is quantified using two key metrics:

1. *Payback Time*, quantified with respect to two conventional benchmark heating systems: (a) electric heater, and (b) gas boiler. Payback times are calculated by estimating the number of years needed to recoup the additional investment into equipment and installation through

savings in operating cost when compared against the two-benchmark technologies. Our approach to assessing the payback times takes into account the impact of key factors, such as the correlation and utilisation of electricity assets and heat requirements, electricity, gas and carbon prices, discount rate etc.

2. *Net Present Value (NPV)* of different cost components over the assumed equipment lifetime. The total cost of each option is disaggregated into equipment, installation, maintenance, energy (gas or electricity) and carbon cost, and expressed as NPV using the assumed discount rate.

The methodology is illustrated on the example of a 15 MVA distribution transformer equipped with an OFWF cooling system, which is considered to be the most practical option for installing heat recovery equipment. Recovery of low-grade heat from transformer losses is based on a system equivalent to Ground Source Heat Pumps (GSHPs), but without the need for underground heat exchangers, as illustrated in Figure 37.

Heat generated by losses in the transformer is transferred from the oil circuit to the water circuit, and is used to improve the performance of the heat pump that supplies heat for space heating. By determining the transformer losses for a given loading level, it is possible to calculate the transformer oil temperatures and use the oil-water cooler model to compute the outlet water temperature, and consequently the COP of the heat pump.

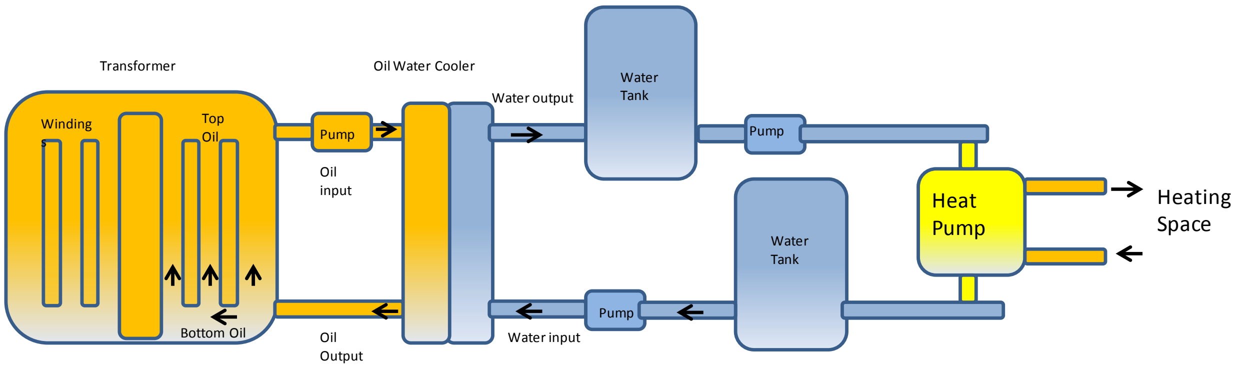


Figure 37: Concept of heat recovery from distribution power transformers

This concept includes a transformer, an oil water cooler, oil and water pumps, a heat pump and heat diffusion (radiators) in the heated space. These elements interact with each other through the following stages in the recovery process:

(a) Electrical losses in the transformer generate heat that is transferred to the oil in the cooling system,

(b) The oil is cooled by pumping it through the oil-water heat exchanger, where the water absorbs heat from oil,

(c) Heat taken up by the water system is low-grade heat, with typical water temperature rises of 10 °C or less,

(d) This low-grade heat from the water can be extracted and transported by using a water-water heat pump, which does not require any boreholes or excavation, given that the low-grade heat is taken from the water in the transformer cooling system rather than extracted from the ground, and

(e) The heat pump increases the water temperature, and pumps hot water through the radiators installed in the heated space (typically offices in commercial buildings).

A range of appropriate models has been used in this study for the transformer, oil-water cooler, heat pump and space heating diffusers in order to compute heat exchanges, temperatures, mass flows and energy consumption for various heat recovery cases. The interaction between these models and input data is illustrated in Figure 38. A more detailed description of the models developed for this study can be found in Appendix 4.

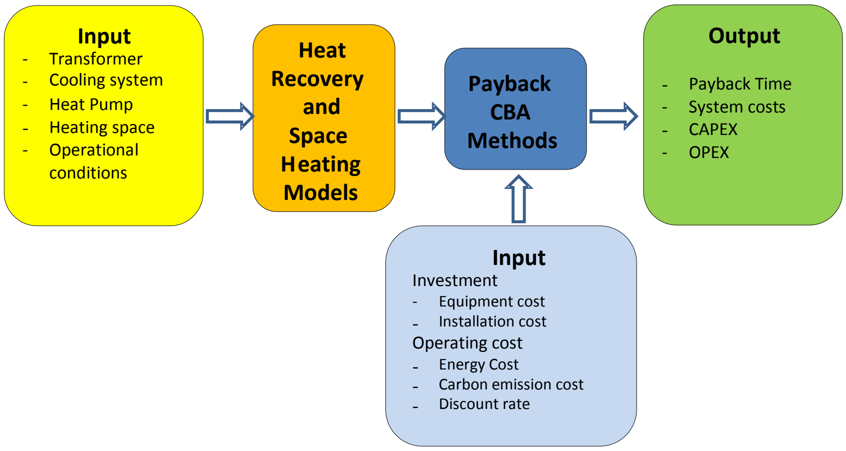


Figure 38: Modelling methodology

This concept, whilst attractive in principle, requires many challenges to be overcome if technical and practical solutions are to be developed which may be economically feasible:

- Risk to compromising the reliability and safety of the primary plant,
- Matching heat supply to demand,
- Relatively low temperature of the heat source.

4.4 Key results of economic valuation and opportunities for application

Case studies in this report include conventional space heating systems (gas boilers and electric heaters), as well as heat pump systems with and without heat recovery from transformer electrical losses. For each of these cases we analysed the impact of varying the annual operating time of the heating system between 25% and 100% on payback time and NPV of the heating system design.

For the purpose of the illustrative analysis carried out, assumptions associated with the cost of equipment, installation and operation are presented in Table 25.

Table 25: Investment and operation cost assumptions for different heating options

Heating option	Equipment cost (£/kW)	Installation cost (£/kW)	Annual maintenance cost (% of investment)	Energy carrier	Cost of energy (£/MWh)	Carbon emission factor (g/kWh)
Gas boiler	38.5	20	3%	Gas	31	185
Electric heater	70	20	2%	Electricity	87	100-235
GSHP	600	800	0.5%	Electricity	87	100-235
Heat pump with recovery	600	250	0.5%	Electricity	87	100-235

It is important to observe that cost of the heat pump and the associated cost of installation are significantly higher than those of a gas boiler or an electric heater. However, we also note that the installation cost of the heat pump with heat recovery is lower than the installation of GSHP as drilling boreholes or installing loops is not needed in order to establish the heat source.

For all heating options the same installed heat capacity is assumed to ensure comparability (although this capacity was varied depending on transformer loading assumptions) and the assumed equipment lifetime is 20 years (we consider that this is a conservative assumption as longer lifetimes would make heat recovery system more attractive). Given the focus on the performance of heat recovery systems in future networks, we assume the average emission factor for grid electricity at 100 g/kWh and the carbon price £73.7/tonne (in line with the GB system in 2030).

Figure 39 presents the calculated ranges of payback times for various heat recovery options, quantified with respect to the two conventional benchmark heating systems: electric heater and gas boiler. Payback times have been calculated by assessing the number of years needed to recoup the additional investment in additional equipment and installation through (discounted) savings in operating cost when compared against the benchmark technology. Minimum payback times in Figure 39 have been calculated based on high transformer loading, high heat pump cycle efficiency and high ambient temperature, while the maximum payback times reflect the opposite end of the spectrum for these three assumptions. The figure shows the impact of discount rate of 3% (Figure 39a) and a high discount rate of 9% (Figure 39b).

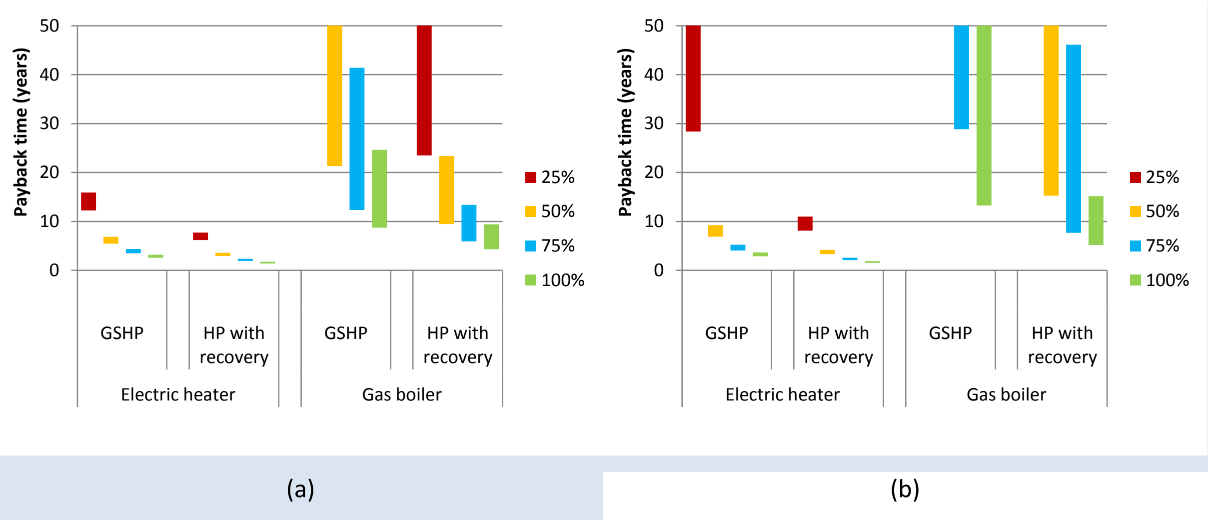


Figure 39: Payback times for heat pump systems with and without heat recovery measured against electric heater and gas boiler, for discount rates of (a) 3% and (b) 9%

The results clearly indicate that heat pumps using the heat recovered from transformer losses perform much better when competing against electric heaters than against gas boiler based heating systems. When compared to electric heaters, the heat recovery system yields a payback time of 5-10 years even with a relatively low operation time of 25%. On the other hand, when a gas boiler is used as the reference, at least 50% operation time is required in order to achieve average payback times of 20 years.

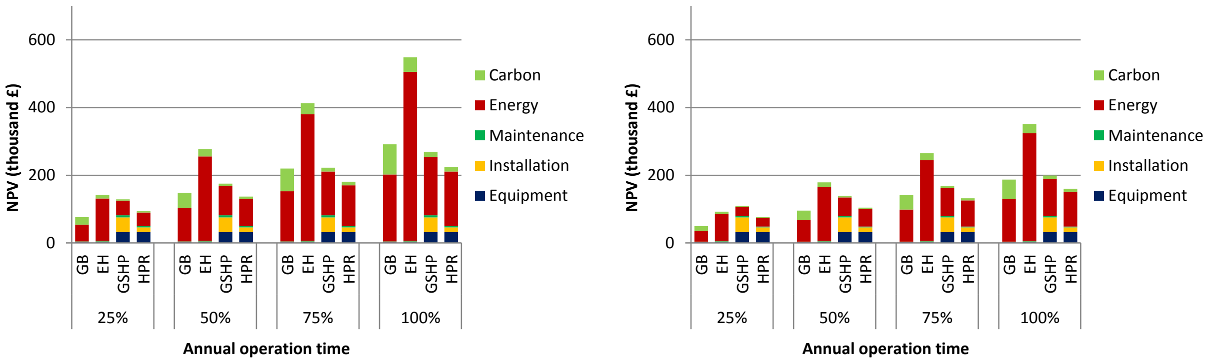
We further note that the utilisation time of a heating system plays a critical role in its economic feasibility. In the case of comparison with the electric heaters, payback periods reduce several times if operation time increases from 25% to 100%. When a gas boiler is used as reference, at least 50% operation time will be needed to bring the minimum payback time of a heat recovery system below 20 years.

Another important finding is that the heat pump system with heat recovery consistently outperforms the GSHP system, which is a direct result of more efficient operation and the lower initial investment cost (given that it does not require the installation of heat exchangers in the ground). However, it needs to be noted that the potential applications of heat recovery systems will be limited to the vicinity of the primary substations.

The results of NPV calculations for alternative heating system designs are presented in Figure 40, where the NPV of each system is separated into different cost components incurred over the assumed 20-year lifetime of the equipment. Comparison of NPVs of different options allows for identifying the least-cost heating system design for a given set of input assumptions. As it would be impractical to present the minimum-maximum ranges of NPV for various parameter assumptions (as in Figure 40), the values included in the figure refer to the central set of assumptions made in our studies.

The total cost of each heating option is disaggregated into the following components:

- Upfront investment cost, further disaggregated into:
    - Equipment cost
    - Installation cost
- Annual operation and maintenance cost, with the following subcomponents:
    - Annual maintenance cost
    - Cost of energy (gas or electricity)
    - Cost of carbon



(a) (b)

Figure 40: NPV of different cost components for alternative heating system designs, for discount rates of (a) 3% and (b) 9% (GB = Gas Boiler, EH = Electric Heater, GSHP = Ground Source Heat Pump, HPR = Heat Pump with Recovery)

The comparison of NPVs is made for the four key heating design alternatives: gas boiler (GB), electric heater (EH), ground source heat pump (GSHP) and heat pump system with heat recovery from transformers (HPR). Annual operation time of heating systems is varied between 25% and 100%, while the impact of the assumed discount rate is also quantified by finding the NPVs for the rates of 3% (Figure 40a) and 9% (Figure 40b).

Similar observations can be made as in the discussion on payback times. Heat pump systems with heat recovery from transformer losses systematically outperform GSHPs regardless of discount rate or operating time assumptions, which is largely the result of a lower installation cost, as discussed above.

Electric heaters appear to be the least cost-efficient option in almost all cases, and the gap between this and other heating system designs increases with the increase in time of operation. This is primarily driven by a high cost of operation, in particular the cost of electricity and the associated cost of carbon. Despite a significantly higher investment cost, heat pump systems with heat recovery generate a lower NPV than electric heaters in all cases presented in Figure 40 because of a substantially lower electricity and carbon cost.

Ensuring the competitiveness of heat recovery systems against gas boilers is a much more difficult proposition, given that the cost of gas is significantly lower than the cost of electricity. Utilisation factors of the heat-recovery based heating system need to reach 50% (in case of a low discount rate) or 75% (in case of a high discount rate) in order for the heat recovery system to become comparable to a gas boiler in terms of NPV. Expectedly, higher discount rates make the options with low operation cost but high investment cost (such as the heat recovery systems) relatively less attractive than low-investment options with higher operating costs (such as gas boilers).

In our assessment we also identified a diverse range of drivers that may influence the results, and ran a number of sensitivity studies to quantify the impact of these drivers on the economic feasibility of waste heat recovery. Parameters that are varied included:

- Radiator temperature requirements (55 °C vs. 45 °C)
- Water flow control (constant flow vs. proportional to loading)
- Average transformer loading (30% / 40% / 50% / 60% / 70% / 80%)
- Ambient temperature (winter average vs. annual average)
- Heat pump cycle efficiency (50% / 60% / 70%)
- Gas, electricity and carbon price (high vs. low values)
- Discount rate used for NPV calculations (3% vs. 9%)
- Transformer loss performance (standard vs. low-loss)
- Availability of heat storage to manage the mismatch between heat generation and demand

Our additional sensitivity studies showed that an increase in transformer loading level or in the heat pump cycle efficiency has a significant positive impact on the feasibility of the heat recovery system. Prices of gas, electricity and carbon have also been found to have a significant impact on payback times and NPVs. For instance, if the gas price doubles, the payback times of heat recovery systems measured against gas boilers are broadly reduced by half.

Sensitivity of payback times of the heat recovery systems with respect to several key parameters is illustrated in Figure 41, for a range of annual operating times. The default case refers to the central set of assumptions based on 70% transformer loading. In situations where multiple transformers operate in parallel to ensure security of supply, the average loading may be expected to be lower (although some empirical data included in the Appendix suggest this is not always the case), so the “low loading” case assumes the loading level of 30%. The expected deployment of low-loss transformers is captured in the “low-loss” case, with losses 50% lower than the standard transformer. Finally, the “heat storage” case assumes that a water tank is installed to enable the matching of hour-to-hour variations in heat generation and demand. The last two cases also assumed the transformer loading of 30%. The results indicate that payback times are not highly sensitive to these assumptions, as although lower loading level or lower losses reduce the volume of heat available for recovery, they are benchmarked against electric heaters or gas boilers of proportionally smaller size. This suggests that the key driver for longer payback periods with lower losses is the reduced temperature at which heat is extracted. Nevertheless, this can to a large extent be mitigated by installing variable flow control to maintain a constant (high) temperature across different transformer loading levels. We also note that the payback time is more sensitive to lower annual operating times and when compared against gas boilers.

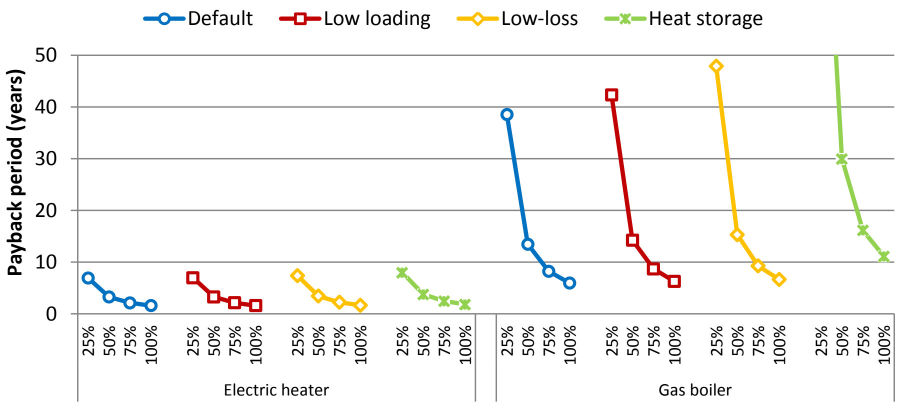


Figure 41: Sensitivity of payback period to different assumptions on parameters of the heat recovery system

In general, all waste heat recovery systems with heat pump technology are more cost-effective alternatives than conventional ground source heat pump systems, as in addition to more efficient operation, the installation cost is substantially lower as drilling boreholes or installing loops is no longer necessary in order to establish a heat source. Heat recovery systems are likely to be a preferred option to electric heaters, with payback times of 5 to 10 years at reasonable annual operation times. When the heat recovery alternatives are compared against gas boilers, their attractiveness is predominantly contingent on the system utilisation levels, which suggests that possibilities of operating heat recovery throughout the year with additional uses for heat, such as provision of hot water and inter-seasonal heat storage, may be very beneficial.

Utilisation of waste heat resulting from electrical transformer losses is an innovative means of heat recovery and can be technically and commercially viable as a low-carbon heating solution. We recognise that a number of technical factors (transformer size and loading, cooling water temperature, heat pump efficiency), economic drivers (energy and carbon prices, discount rates) and practical constraints will affect the feasibility of heat recovery systems. We conclude that the recovery of heat from EHV transformers, which provide the greatest concentration of loss on the distribution network, is potentially commercially viable. Developments to date have demonstrated that this is technically and practically feasible. Heat recovery systems are likely to be a viable investment when the alternatives are based on electric heaters.

Extending the operating time of heating systems by using the heat pump for heating in winter and cooling in summer may be beneficial, although it would add complexity to the system. This topic requires further research, which should also incorporate the capabilities of heat storage to mitigate excesses and surpluses of heat occurring due to diurnal and seasonal variations. Further demonstration projects on heat recovery are recommended in order to further improve the technical knowledge base and better understand commercial performance.

A number of supporting mechanisms can be expected to apply to heat recovery in the near future. Heat recovered from transformers and utilised instead of fossil fuel sources will benefit from avoiding carbon taxes such as the Climate Change Levy (CCL), the European Union's Emissions Trading System and the new carbon price floor mechanism. Avoidance of the latter is likely to prove particularly attractive if it is implemented as planned. In addition, it is possible that waste heat recovery from transformers could benefit from enhanced capital allowances in future if the technology was deemed eligible. Heat pumps systems that combine heat recovery from transformers might also benefit from the Renewable Heat Incentive (RHI) in future. The use of a non-natural heat source, such as heat from a transformer, disqualifies a heat pump system from the RHI subsidy under current legislation. However, DECC are currently considering arguments for the proportion of naturally occurring heat extracted from the ground or the air, which is defined as renewable, to be eligible in future provided that the overall system meets the required technical standards.

Recommendation 16: An Innovation Project, based upon learning from this initial Study, may be initiated in order to gather further insight into the technical and practical solutions which can be tested at more sites. The Project could be scoped to also tackle the regulatory and commercial market structural issues which will also need to be overcome to bring heat recovery and use into mainstream application.

Recommendation 17: DNOs may maintain an awareness of the potential for heat recovery when planning the installation of EHV transformers and seek to install more systems where the recovered heat may be of commercial use.

4.5 Heat recovery from cables

There are a number of different forced cable cooling systems that could form the basis for heat recovery, including:

- Those which control the environmental conditions in which the cables are laid i.e. irrigation of the backfill or separate-pipe cooling;
- Those which directly cool the cable surface i.e. trough and weir water cooling, forced air cooling or integral-pipe cooling;
- Those which cool the cable from within i.e. internal water or oil cooling;
- Those which alter the characteristics of the conductor material using cryogenic techniques i.e. cryoresistive or superconductive cables.

One of the main issues with cable cooling is the lateral nature of the cooling flow, leading to increased temperatures of the cooling medium (and loss of cooling capability) as it flows along the cable. This puts a limit on the length of cable which can be cooled without “refreshing” the cooling medium, e.g. by venting air to the atmosphere. Consequently, at present, most cable cooling is carried out in discrete locations where there are risks of high temperatures, such as within cable ducts.

The greatest potential for heat recovery will therefore exist at sites with concentrations of cables, as well as the sites where cooling might be an issue so there is an additional incentive to collect and remove heat. However, to be commercially attractive, a nearby heat demand would be required, thereby reducing potential opportunities. In addition, harvesting heat from cables is likely to prove most attractive for new build installations as retrofit is unlikely to be economic due to the costs of exposing cables, laying heat recovery loops and re-laying cables.

Further work is needed to demonstrate the technical and economic feasibility of harvesting heat from cables and this would require engagement with several interested parties. However, with appropriate instrumentation, this could also be explored as part of transformer heat recovery project to minimise costs.

We have been unable to identify any stand-alone cable heat recovery projects. Retrofit cable projects do not appear attractive given the cost of laying heat recovery systems over existing cables. There have however been projects where the cable heat recovery has been an additional bonus to the main transformer heat source, such as e.g. Birmingham Market project by Central Networks. Also, Rook Services at its Hurst installation recovers additional heat from cables leading to/from the transformers in the cable troughs through running its pipework alongside the existing cables to improve the performance.

Our assessment of the potentially available heat from typical DNO cables has been done using first principles and the data for a 33 kV cable obtained from one of the principal DNO suppliers. This analysis suggests it is unlikely that heat recovery from buried cables will be cost-effective unless there is also a need for cable cooling. Cable cooling is standard practice in some cable tunnels but this is usually achieved through air circulation which has a low value for heat recovery and is simply vented to atmosphere.

We have also found no projects where the recovery of heat from cables and transformers together has been engineered from the outset. In most cases the cable heat recovery has been an additional bonus to the main transformer heat source. Integrating heat recovery from “transformer cables” at the design stage is likely to prove attractive although there is no detailed monitoring data available to illustrate this. Further research is required to establish whether natural heat exchange, such as Rook Services’ Hurst installation, or forced systems, prove most attractive.

In summary, we conclude that heat from cables may contribute to the overall heat available in those cases where a non-intrusive recovery system is proposed for the transformer. However there is no evidence of examples of the successful use of heat recovery from cables only and we conclude that further work in this area is not a priority.

4.6 Opportunities for deployment of heat storage

Our analysis demonstrated that the business case for recovery of low-grade waste heat from electrical losses in distribution networks will depend on the level of coincidence of heat demand and supply. Heat storage could provide additional benefits for heat recovery systems by mitigating the mismatch between heat availability and heat demand over the course of a day or a year. Three types of heat storage are of particular interest for heat recovery applications: 1) ground heat/cool for long-term storage with heat pumps, 2) large-volume insulated water tanks, and 3) smaller Phase Change Modules (PCM). The commercial viability of heat recovery could be enhanced by utilising heat storage, but the benefits of long-term ground storage against short-term water or PCM storage need to be further investigated due to the risks associated with complex systems of this type and increased costs associated with storage related investment and operation costs.

There are an increasing number of ground-based heat storage projects, mainly driven by the need to cool spaces. There are several GI Energy schemes implemented in the UK (Sainsbury’s, Carlisle and Crossrail), as well as similar schemes in Finland, Austria and Switzerland. The ground thermal storage concept is readily transferable to heat recovery from transformers and cables, and its implementation should be more straightforward than e.g. the Sainsbury’s scheme as it does not require the complicated control system associated with the refrigeration part of the system.

GSHPs have traditionally used bore holes to extract heat in the winter and dump heat (in reverse cycle) in the summer for cooling. The UK heat/cool cycle is such that there is a greater demand for heat than cooling so there has to be “natural” net heat flow into the bore holes to maintain the equilibrium. This could be supplemented by electrical system heat recovery in the summer but this would add additional complexity to systems which are already marginally cost-effective.

Water tanks have been used for heat storage in a number of applications. Often referred to as “buffer” tanks, these take the excess heat generated in a boiler or combined heat and power plant at times of low heat demand (which enables the plant to run at optimum efficiency) and then feeds the heat back to the primary circuit at times of high demand, avoiding the infrequent use of additional plant capacity. Due to volume limitations, this heat storage is fairly short-term with a maximum “swing” between input and output of 24 hours.

The use of PCMs relies on the physical characteristics of some materials to change from a solid to a liquid state at high temperatures. Heat is absorbed by the material as it liquefies and then released if it is allowed to cool. A PCM system occupies about half the space of a water tank for the same heat storage capacity, but is about five times more costly and hence can only be justified in locations where space is at a premium. These systems are often used in underfloor heat exchangers to provide peak cooling for air conditioned offices where there are space constraints on the chiller plant.

Both water and PCM heat storage systems would be capable of operating on a diurnal basis but it is unlikely that sufficient capacity could be created for inter-seasonal storage. The only successful long-term storage is based on GSHP units using the ground capacity as a long-term store.

The commercial viability of heat recovery could be enhanced by utilising heat storage, but the benefits of long-term ground storage against short-term water or PCM storage need to be further investigated due to the risks associated with complex systems of this type.

Recommendation 18: Further work on heat storage may be integrated with future trials work on recovery of heat from the distribution network, as it may improve the economics of more basic heat recovery systems.

5 Policy implications of the losses studies

5.1 General

In relation to network losses incentives, Ofgem states that "Electrical losses are an inevitable consequence of transferring electricity across the distribution network and they have a significant financial and environmental impact on consumers. For example they contribute to approximately 1.5% of GB's greenhouse gas emissions".

For the many reasons described in this Report, the losses on electricity distribution networks in GB have been somewhere between 5% and 7% of units distributed for over thirty years[18]. This is not unduly high when compared with the efficiency of distribution systems in less developed countries, but it is in the interests of consumers and society at large that every effort is made to manage losses in an economically efficient manner. Losses remain an important factor in the overall management of any electricity distribution business in relation to security of supply, the potential of higher energy costs and concerns for the impact on climate change of carbon dioxide emissions.

One key area of policy which we have not examined is the opportunities in which security of supply reduction could be valued against a reduction in losses. For example losses may be reduced by using teed 11kV substations in designs where looped substations are currently require. Another example may be the reduction of iron loss which could be achieved by having the second transformer switched out at a low load factor EHV substation. WE believe that this trade-off can only be considered in economic terms and we would see the valuation of continuity of supply as beyond our remit in this Study.

5.2 Energy efficiency of distribution networks

Energy efficiency is usually defined as the ratio of energy output to energy input but for electricity distribution this is not meaningful as there will always be some unavoidable loss due voltage conversion and cable losses. Therefore, we consider that energy efficiency can only be assessed in terms of economic efficiency. We may consider those parts of the network with high losses as "energy inefficient" and those parts of the network with low losses as "very energy efficient". Networks are highly non-homogeneous and therefore an accurate overall level of network loss remains a very important goal in considering what may or may not be energy efficient.

A reasonable assessment of an energy efficient network is one in which no further reduction in losses can be achieved without spending more than the loss reduction valuation to do so.

This approach to loss management may be seen in strategic work recently undertaken by ESB[19]: *In ESB Networks all investment decisions incorporate the capitalized value of losses, so that the Total Cost of ownership is included in all cost/benefit analyses. Furthermore by capitalizing the losses consistently at the same discount rate across all voltage levels, there is no sub-optimization of investment in any one part of the network – in contrast, adopting simple set limits of losses for (say) Transformers alone would produce suboptimal savings*.

[18] Distribution network developers and designers in the 1970s and 1980s applied simple deterministic techniques in order to assess network losses and the figure of 7% was typical. In addition, the figure correlated with the then Electricity Board's accountants' sales/purchase ratios which were usually of the order of 93%.

[19] http://www.cired.net/publications/cired2011/part1/papers/CIRED2011_1143_final.pdf C I R E D 21st International Conference on Electricity Distribution Frankfurt, 6-9 June 2011 Paper 1143

5.3 The interaction of network utilisation and losses

Traditional distribution networks have been designed, built and managed in a manner which has been fit-for-purpose over many years in delivering power to consumers. In general, the power flow in passive networks has been from higher to lower voltage networks. HV and EHV networks have been designed for security and hence peak utilisation is consequently relatively low.

In contrast, active network schemes usually involve the deployment of intelligent systems which can enable networks to be operated closer to technical limits of voltage, current and fault level whilst still remaining safe and meeting planning/security standards of supply.

In placing losses into the overall context of network management, we need to consider the relationships between plant/equipment loadings, load profile, ratings and losses:

- The utilisation factor (PUF) of plant/equipment is defined as the ratio of peak load in the plant/equipment to the plant/equipment rating
- The load factor (LF) is defined as the ratio of the average load to the peak load
- The loss load factor (LLF) is defined as the ratio of the average load loss to the peak load loss
- The rating is defined as the maximum load which can be technically and safely carried by the plant/equipment.

As the rating is dependent upon an assumed load profile, we may anticipate it will vary as profiles will change due to different load shapes driven by EV charging, heat pumps and distributed generation. We will also see changes to profile due to DNO interventions and smartgrid solutions designed to improve load factor.

Changes to losses on future networks will be either adverse or favourable, depending upon chosen management policies. If load factor can be increased whilst delivering the same amount of energy then losses will decrease. However, if the load factor increase is used to allow more capacity headroom thus returning to the same PUF or higher, then losses will increase.

It is our view that, when working on any specific network project proposals, the cost-benefits of chosen options of network loading will include the impact of losses and in applying pre-determined investment criteria, the right choice will be made of whether to use or not use any available capacity, however it may have been created.

In the negotiations between Ofgem the regulator and the DNOs, there is extensive discussion regarding the nature and costs of the network companies' investment plans. In the present price control period (2010 -2015), the plans include "load-related investment" at most sites which have reached 'Load Index 5 (LI5)' status, defined as where demand exceeds 98% of rating for more than 8 hours in any year. Naturally, those sites which experience the highest utilisation will also have higher losses.

As demonstrated through our loss-inclusive network design, peak demand in LV and HV networks should not exceed 25% of the thermal rating of the corresponding conductors. This also demonstrates that the peak-demand driven network design, although it would minimise short-term network reinforcement cost, would increase the cost of energy production and in fact lead to overall higher costs to consumers.

We also point out that inefficient peak-demand driven network design would expose consumers to further increases in network costs driven by network reinforcements if sufficient capacity headroom has not been made available to accommodate demand growth. Clearly, the very significant capacity headroom that is associated with loss-inclusive network design philosophy, which is indeed economically efficient, will clearly provide a significant hedge against uncertainties in future load and generation growth. The prospect of further increase in energy cost associated with investment in low carbon generation technologies (e.g. nuclear and renewables) to reduce carbon dioxide emissions, presents a further liability inherently associated with peak-demand driven design, as the cost of losses would further increase and hence the cost to consumers. These factors justify full consideration of losses in investment decisions.

5.4 DNOs' Business Plans

As described in more detail in Appendix 5, DNOs have historically based their valuations of losses on the incentive mechanisms established by Ofgem throughout various price controls since 1990. For the future, loss valuation is being considered in the context of the price controls from 2015 inwards under the RIIO (Revenue = Incentives + Innovation + Outputs) Model.

In their 2015-2023 Business Plans submitted to Ofgem, DNOs identify various investment options which satisfy cost-benefit criteria to deliver efficient networks in the short, medium and long-term. Network design will include giving the right priority to network losses and Ofgem has clearly stated a set of rules for cost-benefit appraisal of loss-reducing measures in the 4th March strategy documentation[20]. The main factors in the cost-benefit assessments under these rules are shown in Table 26.

Table 26: Ofgem guidance on assessment of losses

Factor	Requirement
Cost benefit analysis	Simple discounted approach
Discounting	Applied to all costs and benefits
Treatment of capital costs	Convert to annual cost using pre-tax Weighted Average Cost of Capital (WACC)
Term of assessment	Assumed economic life of the asset up to 45 years
Test discount rate	3.5% for costs and benefits
Value of energy loss reduction	The average of wholesale prices over 2011/12. This is £48.42/MWh in 2012/13 prices.
Value of carbon abatement	DECC's latest valuation https://www.gov.uk/carbon-valuation. For the power sector a linear carbon regression is applied from the present value to 10g/kWh in 2050 in order to reflect decarbonisation policy.

It is clear the choice of a 3.5% test discount rate and 45-year life is very important in providing a bias towards the prudent approach of investing in future networks. By applying Ofgem's guidance on avoided loss investment valuation spreadsheet, a 1MWh reduction in lost energy sustained over 45 years is worth £1,451 in 2012/13 prices.

As demonstrated through our loss-inclusive network design, maximum loading of LV and HV underground network as a percentage of full loading should be no higher than 12-27% of its thermal rating, while for overhead network maximum loading should not exceed 8-19% of the thermal rating. This very significant capacity headroom, that is also economically efficient, will clearly provide a significant hedge against uncertainties of future load and generation growth. Furthermore, the role of alternative smartgrid solutions and technologies in future networks based on loss-inclusive design will shift from enhancing network utilisation to reducing losses.

Recommendation 19: DNOs should develop loss-inclusive network design strategies, based on their specific data, in order to ensure that the overall economic network operation and design criteria are met. This should include network modelling capability for answering "what-if" questions in order to predict the impact of proposed network polices, projects and network demand forecasts on the overall reported network losses.

[20] RIIO-ED1 team – Ofgem, Strategy decision for RIIO-ED1 electricity distribution price control, Final decision, Reference: 26/13, 4th March 2013, https://www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview

DNOs Business Plans for the period 2015-2023 have been submitted to Ofgem. In the publication of their assessment of the plans on the 22nd November 2013[21], Ofgem have indicated that in general they wish to see changes to the DNOs' proposed approach to management of losses:

"The majority of DNOs submitted strategies for the management of losses, although we were disappointed across the board with the standard of the associated cost benefit analysis and the level of ambition."

We observe that DNOs have taken different approaches to including losses in their investment decision-making. Within the uncertainties of future needs, it would be desirable to establish a common basis for development of loss mitigation and loss-inclusive network design policies that would be in line with both national interest and DNOs' business objectives.

Recommendation 20: DNOs, with support from DECC and Ofgem, may determine the common basis in relation to loss mitigation and loss-inclusive network design and investment.

In our view, it is very important that loss-inclusive network design should be put into practice within the next few years. In the very large investment programmes planned by DNOs, due consideration of the significance of losses is required in the move towards more energy efficient networks. We note that extensive work has already been completed by DNOs and Ofgem in developing Business Plans and additional investment for loss-inclusion in network capital projects will require further consideration. A solution should be found, for example the provision of a fixed percentage of capex to fund the additional costs of loss-inclusive design compared with the more traditional approach to best value investments. The new philosophy may be introduced at the beginning of the RIIO-ED1 price control period, and as better knowledge and more network information emerges through the many innovative network management solutions currently being developed, new loss-inclusive policies and practices may be fully-incorporated by the start of the RIIO-ED2 period.

5.5 Connections Policy

The loss-inclusive design philosophy has a significant impact on connections charging policy. Currently, clients seeking connection to the network pay the minimum charge for connection as defined by what assets are required to meet technical standards of safety, volt drop, current rating etc, but not including any additional capacity which may be specified to achieve economic levels of loss. If the DNO con justify a more expensive scheme than the minimum as traditionally defined, the additional charges are socialised, being recovered through general DUoS charges.

We consider that, consistent with the principle of economic loss management, the minimum cost of the scheme should include those costs which are justified to optimise losses. This proposed change has significant implications for connections policy, namely:

- the impact on Developers' costs;
- the impact on competition in connections;
- new obligations on IDNOs to avoid preferences being afforded to lower cost "high-loss" designs
- less socialising cost within DUoS charges

New policy developments will require discussions between DNOs and Ofgem. There will be extensive stakeholder interest in the proposed changes and a considerable lead time may be anticipated to develop new policy with proportionate levels of debate and consultation.

[21] https://www.ofgem.gov.uk/sites/default/files/docs/2013/11/assessment_of_the_riio-ed1_business_plans_0.pdf

5.6 Long term electricity and carbon prices

For loss-inclusive design, network policies and network project specifications are significantly affected by the assumption of forward electricity value and carbon abatement values. Already, Ofgem's guidance on future electricity costs support more active consideration of losses in investment decisions. Our analysis demonstrated that the loss-inclusive network design will be sensitive to assumptions of electricity costs.

We note the loss-inclusive network design carried out using the chosen assumptions is perhaps understating the value of loss mitigation as:

1. The average electricity price does not take into account that variable losses are proportional to the square of demand, and are much larger at times of peak network demands, which in general coincide with peak national demand, when the cost of electricity may be significantly higher, and
2. The analysis did not include carbon prices and was based on relatively low energy prices of £45/MWh, particularly in the light of the recent announcement that the strike price for new nuclear has been agreed at £92.50/MWh.

Recommendation 21: There is a need to establish the basis for assumptions on future electricity costs and carbon prices that would be used in loss-inclusive network investment that is consistent with the overall UK low carbon policy.

5.7 Obligations and standards

Governments and regulators throughout the world require network operators to build and run efficient networks. Inevitably, with attention given primarily to reliability of delivery of power and operating safely, losses have been less of a feature in the general consideration and understanding of "efficient" operation.

In GB the obligations to achieve an efficient level of losses exist within the Licence Obligation for both DNOs and Independent Network Operators. A new set of regulatory obligations will be established under RIIO-ED1 for the period 2015-2023, during which time further developments in loss management may lead to a return to the establishment of a new incentive regime for loss reduction 2023 onwards.

Design standards worldwide vary significantly in their loss inclusiveness. Some background information on loss standards in GB, EU and the USA is provided in Appendix 6.

In addition to new economic appraisal of the value of losses currently being developed by Ofgem and the GB DNOs, there may be changes to equipment specifications required by the EU Initiative *"Directive 2009/125/EC of the European Parliament and of the Council establishing a framework for the setting of ecodesign requirements for energy-related products"*. This may require GB to adopt higher standards of energy efficiency for distribution transformers by specifying lower loss designs, although our general view is that the economics of avoiding losses are such that DNOs will wish to specify better loss performance regardless of the existence or otherwise of the Standards. The current status of the Directive is described in Appendix 6.

5.8 Monitoring and reporting of overall loss levels

It is likely that the overall level of losses for each GB distribution network as a percentage of electricity supplied to the consumer or entering the distribution network will continue to play a part in network loss management. Such a figure is an indicator of trends towards an efficient level of losses and it remains an ongoing aspiration of DNOs and Ofgem that the percentage loss may be calculated and/or measured, and to which a reasonable level of confidence may be ascribed. This is not the case at present, and there is insufficient confidence in the reporting of overall loss either as a trend, or between DNOs, or for incentive purposes or for comparing GB with overseas companies. The Study considers the factors which impede the use of the overall loss figures for such management purposes. GB losses are discussed in some detail in Appendix 7.

Ofgem's consultations on the Distribution Price Control loss incentives from 2005-2010 provide an indication of the complexity of loss reporting based upon losses reported through the GB Settlements arrangements. We believe that more detailed analytical work will be required in both the technical and non-technical loss drivers to improve loss reporting.

Whilst the loss incentive has been abandoned for the RIIO-ED1 price control period, it is important that an early start is made to planning how losses are going to be measured and reported more accurately in the future. Ofgem's aspiration is to return to a loss-incentive mechanism in RIIO-ED2 from 2023 onwards. Whilst it may seem that this is sufficiently far into the future to not be today's priority, it is likely that significant lead time is required to develop new measuring and reporting systems, and an early start is required. This is especially the case in order to have confidence in a new measuring regime before negotiations on RIIO-ED2 commence.

Whilst meeting Ofgem's requirements is an important motivator towards better loss measurement and reporting, networks strategists and managers will also have increasing confidence in their decision-making if their policy and planning activities are informed by better data on losses. Although many key network decisions may be location-specific and there is limited use which can be made of the overall loss reports in practical network design work on specific parts of the network, they remain an important performance indicator.

In the next few years, Ofgem intends that loss assessment will become more accurate in order that there may be a return to incentive-based loss management from 2023 onwards. Between now and 2023, it is anticipated that DNOs will be moving towards more energy efficient loss inclusive network design and the impact of such action be reflected in the reported overall network loss figures.

Recommendation 22: Early in the RIIO-ED1 period, DNOs may develop more accurate means of measuring and reporting of distribution network losses.

The disparity in reported losses between Government (DUKES data) and Ofgem has been identified in the Study, see Figure 42. The Ofgem figures have been the focus of attention, and in our view provide a more appropriate reflection of reality as work has been done on the "raw" data to factor-in adjustments, in particular those relating to Settlements reconciliations.

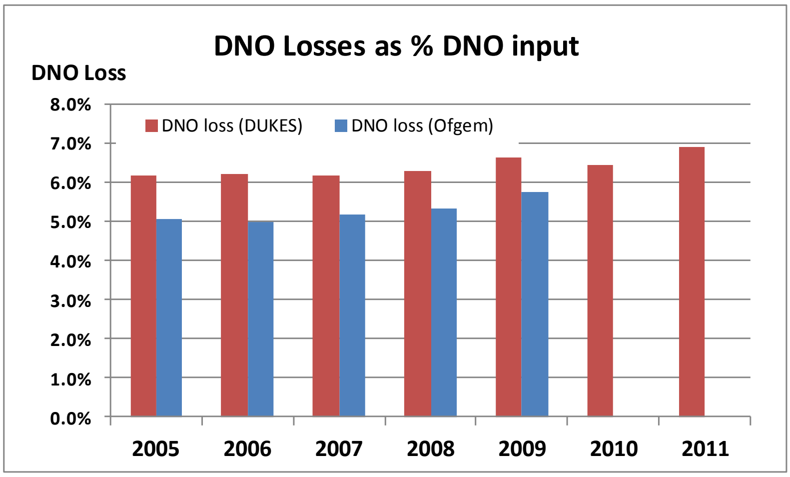


Figure 42: Reported losses from DUKES and Ofgem

The DECC reports may be of less significance and of less relevance to the interests of DNOs. However, there is a risk that the DECC data is used by Government and is also collected and used internationally, possibly presenting GB losses as high when making international comparisons. We do not believe that this is in the best interests of GB DNOs and it is a matter which DNOs should address.

Recommendation 23: The DECC/Ofgem comparison of reported losses shows a discrepancy which may cause a distorted view of GB DNO losses, within industry, government and internationally.

5.9 International comparisons

Appendix 8 includes comparisons of network losses in various countries and describes the factors affecting the validity of the comparisons. GB DNOs may be disadvantaged by misleading comparisons due to the inconsistent approaches to reporting between countries. DNOs may seek to qualify the comparisons being made when suitable opportunities arise to influence opinion on the international stage.

Recommendation 24: DNOs may grasp opportunities as they may arise to influence loss reporting in other countries and as it is presented in international studies. This is in order to ensure that GB DNOs' loss management performance is presented accurately.

5.10 Policy to facilitate waste heat recovery

A number of supporting mechanisms can be expected to apply to heat recovery in the near future. Heat recovered from transformers and utilised instead of fossil fuel sources will benefit from avoiding carbon taxes such as the Climate Change Levy (CCL), the European Union's Emissions Trading System and the new carbon price floor mechanism. Avoidance of the latter is likely to prove particularly attractive if it is implemented as planned. In addition, it is possible that waste heat recovery from transformers could benefit from enhanced capital allowances in future if the technology was deemed eligible.

Heat pumps systems that combine heat recovery from transformers might also benefit from the Renewable Heat Incentive (RHI) in future. The use of a non-natural heat source, such as heat from a transformer, disqualifies a heat pump system from the RHI subsidy under current legislation. However, DECC are currently considering arguments for the proportion of naturally occurring heat extracted from the ground or the air, which is defined as renewable, to be eligible in future provided that the overall system meets the required technical standards.

Recommendation 25: Industry, government and regulators should consider developing appropriate regulatory and commercial frameworks that would facilitate development of loss-generated heat schemes where economically justified.

5.11 Barriers to implementation

The concept of providing an energy-efficient distribution network is clear and in principle is highly desirable. The question therefore is why this has not been achieved and we identify some of the barriers to further development:

- Economics: as has been described above, the value of losses may not have justified the additional cost of investment to achieve networks of lower overall loss than are being achieved in GB today;
- Loss evaluation: without sufficient understanding of the level of technical loss either overall or within specific sections of the power network, it is not possible to have an assurance of what is or is not being achieved;
- Regulatory incentive mechanism: the incentive has not been effective, firstly because it has been traded against regulatory pressure and other incentives to reduce investment costs. Secondly it has not been possible to administer the incentive as the overall losses could not

be measured correctly due to reporting irregularities and distortion of the measurement due to well-reported matters relating to non-technical losses;

- Loss targets: There is a lack of understanding of what is the overall economic level of loss within a distribution system. Regional, national and international comparisons do not provide sufficient insight;
- Affordability: this is a fundamental societal issue, requiring a determination of the fair and affordable level of investment which should be paid today to ensure that customers in the future do not endure excessive energy costs relating to network losses;
- Uncertainty: uncertainty of future network demands creates the risk of over-investment and stranded assets of loss-inclusive design commitments are made and anticipated demand is not realised;
- Technology: technology may have limited the progress which may be made in reducing iron losses but that is no longer the case and technology may now be seen as positive enabler in loss inclusive design;
- Data capture: DNOs may not have sufficient data nor at sufficient level of granularity to evaluate and manage losses;
- Computing power: DNOs may not have sufficient computing power to manage large data sets for time-sliced analysis as required to provide a more accurate understanding of losses;
- Competition: competition in connections work and private network ownership has tended towards minimum-cost schemes. There are regulatory policy means of overcoming these barriers;
- Network utilisation: for variable losses there is an important interaction between achieving better utilisation and limiting loss. The trade-off between lower losses and lower capital investments can be assessed by the usual decision-making methods of risk-based project appraisal, incorporating best assumptions of network costs, future demands and generation levels and profiles, future energy costs and carbon abatement evaluation;
- Practicalities: achieving the economic level of losses may be physically constrained by practical issues, such as the limits of length of larger cables which can be accommodated on a cable drum; and
- Culture: it is in “the DNA” of DNOs to consider the best and most economic means of delivering electricity safely and reliably. However, the losses within the individual parts of the network and of the overall network have been a consequence of actions taken rather than an objective to be achieved through appropriate network design and choice of equipment. In the transformation to smartgrids, this point can be addressed.

It will be possible to overcome these barriers. The increasing risk of long-term high energy prices and climate change concerns are the key factor stimulating greater attention to be paid to losses. This is already recognised in the regulatory obligations and loss valuation guidance within ED1 which will provide an effective stimulant to progress towards loss inclusive design.

Some of the enabling technologies within smartgrid solutions will provide better loss evaluation, improved understanding and better overall loss management.

Recommendation 26: DNOs’ loss strategies may be “stress tested” to demonstrate that they can deliver an objective of achieving an economic level of losses based upon avoided loss valuation, engineering costs and future network demands.

5.12 “Whole system” policy

The economic management of network losses require focussed learning of the nature, location and magnitude of loss both in real time and over different time periods, in order to understand them better and to apply appropriate mitigation actions within both design and operation. However the wider implications of losses beyond the distribution network itself across other parts of the value chain need to be considered at all times. A consequence of reduced network losses is a reduced requirement for generation, with the greatest value being at the time of the greatest cost of generation i.e. at system peak, in those cases where peak network demands are reasonable concurrent with peak national power demand.

Looking forwards, the valuations of avoided energy will include increasingly market-based valuations of carbon dioxide abatement and potentially higher valuation of energy due to higher costs of generation. With this scenario, it is important to the risk of losses increasing due to higher utilisation of distribution networks through the electrification of energy through increasing use of heat pumps and electric vehicles.

In this context, it is appropriate to take the “whole system” view of loss strategy, from the consumers’ demand and generation of energy through to the use of fossil and non-fossil fuels for production of heat and electricity. In future, a holistic view across the various sectors of the energy industry will provide the right valuations to justify DNOs’ actions on both network loss management and use of heat.

The analyses from this Study, such as the impact of consumers’ power factor and the sensitivity to various avoided loss valuations, exemplify the approach which may be taken in the future.

6 Conclusions and Next Steps

Many issues relating to electricity distribution loss management have been examined and the Recommendations which are presented throughout the Report are listed in Annex 1.

Loss-inclusive network design is economically justified and the consequences of this change are very significant in terms of engineering policy and capital investment.

In networks infrastructure businesses, it takes a long time to make significant changes to the overall assets and network managers will only be able to make a real impact on total network losses incrementally. Plans are being developed by DNOs to address losses and to satisfy Ofgem's requirements for effective loss management in the RIIO-ED1 Price Control period (2015-2023). This will include developing the capabilities to return to incentive-based loss regulation in the following Price Control Period, RIIO-ED2, from 2023 onwards.

We conclude that it is possible and justifiable to make a start on loss-inclusive design early within the RIIO-ED1 period. At this stage of study work, it is premature to predict the level of impact on overall losses and the benefits which may be achieved by the initiatives considered in this Study. However, further progress can be made through a committed work programme which addresses all of the issues raised within the Study in parallel.

From our work we make five key observations for future policy:

1. **Investment for network energy efficiency**. For future electricity consumers, there are compelling reasons to develop networks and energy-side relationships to ensure that the distribution system is energy efficient. Energy efficiency may be defined by comparing the economic value of avoided loss against the incremental cost of such loss avoidance. The economic value of avoidable loss includes both the forward cost of energy and the value of carbon abatement. It is possible to develop a strategy which resolves the dilemma of over- or under-investing today in relation to the requirements of future customers;
2. **Regulation.** There are strong obligations on DNOs to operate the networks in a safe manner and to a prescribed level of reliability (Engineering Recommendation P2/6). However there is no requirement of real significance to design the network to a prescribed level of losses, as is the case in some other countries. Loss-inclusive network design is economically justifiable and can be developed within the next price-control period, RIIO-ED1, in order to provide a return to incentive-based regulation of loss management in RIIO-ED2;
3. **Understanding losses**. With modern computing power, good data management and additional network monitoring, the location and magnitude of losses in specific parts of the network can be much better understood in order to assist in selecting the right investment options. Similarly, the confidence in reported overall levels of network loss can be improved in order to assist network owners, managers, government and regulators in shaping their views of the energy efficiency of the distribution network;
4. **Loss-inclusive network design techniques.** There are several identifiable opportunities for cost-effective management of losses through interventions on the existing network and design of future networks. Smartgrid enabling technologies, including smart meters, will be invaluable in making these improvements although there is a tension between some objectives of smartgrid solutions and the pursuit of network energy efficiency;
5. **Valuing heat**. The remit of the DNO may extend beyond the management of electrical loss to the management of the consequences of electrical loss, namely heat, which has potential value in those locations where it may be harvested and used. There are several examples of heat-valuation but better-controlled field trials are required in order to progress towards commercial applications.

Supported by the illustrative analysis of losses and cost-benefit studies plus research, we conclude that:

- Network losses should be included within network design policy and that network energy efficiency should rank alongside safety and security of supply in the objectives of overall network management;
- There are several economically viable interventions on existing networks which, together with new design policies, will enable the move to higher network energy efficiency;
- There is evidence of technical and practical solutions to harvest and use heat generated by electrical loss in order to improve overall energy efficiency of running the network. However, more work is required if the developments are to be deployed in those cases where there may be a match between heat demand and heat generation from the network. Also, DNOs will need to consider how to prioritise the longer-term opportunities for heat whilst maintaining their focus on improving knowledge and management of electrical energy losses.

We trust that this Study has illustrated the potential for loss management and that DNOs may adopt the proposals and take actions to embrace the principle of loss inclusion in network management. The Recommendations of our work are listed in Annex 1.

To move forwards, we would anticipate that DNOs may develop a long-term plan to discover new knowledge of network losses and to develop network policies, standards and network designs for future networks which may be demonstrably best practice in electrical power distribution.

Annex 1: List of Recommendations