IMP/001/103 – Code of Practice for the Methodology of Assessing Losses

1. Purpose

The purpose of this document is to state the Northern Powergrid approach and to provide guidance for the methodology of calculating the losses and carbon emissions associated with the operation of distribution system. The document sets out the key assumptions made in the methodology and describes the process for the calculation of the losses, accompanied by worked examples. The document applies to the distribution systems of both Northern Powergrid Northeast and Northern Powergrid Yorkshire, the licenced distributors of Northern Powergrid.

The objective of this document is to inform the development of an economical and efficient distribution system, by providing guidance on the assessment of the economic value of system losses over the life of an asset or design solution. This Code of Practice thereby helps to ensure compliance with the Electricity Act 1989 (as amended) (the Act) and Standard Licence Condition 49.

This document supersedes the following documents, all copies of which should be withdrawn from circulation.

Reference	Title	Version	Date
IMP/001/103	Code of Practice for the Methodology of Assessing Losses	5.0	March 2019
IMP/001/103	Code of Practice for the Methodology of Assessing Losses	4.1	January 2018
IMP/001/103	Code of Practice for the Methodology of Assessing Losses	4.0	July 2016
IMP/001/103	Code of Practice for the Assessment of Asset-Specific Losses	3.1	September 2011

2. Scope

The scope includes the following:

- The consideration of technical losses arising from operation of the distribution system. Non-technical losses due to theft for example are outside the scope of this document;
- The definition, network modelling, assessment and calculation methodology of the losses;
- Application of the methodology where there is a requirement to calculate losses on new assets to be installed or adopted by Northern Powergrid that form part of the distribution systems of Northern Powergrid Northeast or Northern Powergrid Yorkshire;
- Application of the calculation methodology to all categories of new assets including transformers, cables and overhead lines[1]; and
- Application of the calculation methodology to project specific network design solutions[2].

This document does not include the process of producing the Loss Adjustment Factors (LAFs) for the purpose of calculating network charges.

1 The document focuses on transformers and conductors, although the principles can be applied to other assets (e.g. reactors).

2 The document can also be used to compare different types of network design solutions to a particular issue.

2.1. Table of Contents

3. Code of Practice

3.1. Assessment of Relevant Drivers

The key internal business drivers relating to the need to calculate distribution losses in the distribution system:

- Financial strength - achieved by developing an integrated distribution system having minimum overall cost including the cost of losses;
- Regulatory integrity - achieved by designing a robust system that meets mandatory and recommended standards;
- Environmental respect - achieved through due consideration being given to the environmental impact of new network developments including the impact on system losses and carbon footprint; and
- Operational excellence - likely achieved through efficient oversizing of assets or design solutions which will increase the operational flexibility and be cost effective over the lifetime of the asset or the design solutions.

The external business drivers relating to the assessment of losses are detailed in the following sections.

3.1.1. Requirements of the Electricity Act 1989 (as amended)

Section 9 (1) of the Electricity Act 1989 (as amended) places an obligation on Distribution Network Operators (DNOs) to develop and maintain an efficient, co-ordinated and economical system of electricity distribution and to facilitate competition in the supply and generation of electricity.

Discharge of this obligation is supported by this document in providing guidelines on the assessment of losses.

3.1.2. Requirements of Northern Powergrid Distribution Licences

Additional external business drivers relating to the assessment of losses in the development of the distribution system are the Distribution Licences applicable to Northern Powergrid Northeast and Northern Powergrid Yorkshire.

Standard Licence Condition 20 (Compliance with core industry documents) requires the licensee to at all times have in force, implement, and comply with the Distribution Code.

Standard Licence Condition 49[3] (Electricity Distribution Losses Management Obligation and Distribution Losses Strategy) requires the licensee to ensure that distribution losses from its distribution system are as low as reasonably practicable and to maintain and act in accordance with its Distribution Losses Strategy[4]. In particular:

- Standard Licence Condition 49.2 requires the licensee to design, build, and operate its distribution system in a manner that can reasonably be expected to ensure that distribution losses are as low as reasonably practicable; and
- Standard Licence Condition 49.3 requires that in designing, building and operating its distribution system the licensee must act in accordance with its Distribution Losses Strategy, having regard to the following:
    - The distribution losses characteristics of new assets to be introduced to its distribution system;
    - Whether and when assets that form part of its distribution system should be replaced or repaired;

3 Came into force in April 2015.

4 Initially stated in Northern Powergrid ED1 Submission Annex 1.4, Strategy for Technical Losses, March 2014 and subsequently revised in controlled updates which can be downloaded from https://www.northernpowergrid.com/losses

- The way that its distribution system is operated under normal operating conditions; and
- Any relevant legislation that may impact on its investment decisions.

3.1.3. Requirements of the Distribution Code

As a distribution licence holder, Northern Powergrid is required to hold, maintain and comply with the Distribution Code of Licensed Distribution Network Operators of Great Britain. The Distribution Code covers all material technical aspects relating to connections to and the operation and use of the distribution systems of the Distribution Network Operators. The Distribution Code is prepared by the Distribution Code Review Panel and is specifically designed to:

- permit the development, maintenance and operation of an efficient, co-ordinated and economic system for the distribution of electricity;
- facilitate competition in the generation and supply of electricity; and
- efficiently discharge the obligations imposed upon DNOs by the distribution licence and comply with the Regulation (where Regulation has the meaning defined in the distribution licence) and any relevant legally binding decision of the European Commission and/or Agency for the Co-operation of Energy Regulators. This objective is particularly relevant given the forthcoming introduction of a suite of European Network Codes which will place additional obligations on Generators and DNOs.

3.2. Key Requirements

The requirement for this Code of Practice is driven by the need to provide guidance on assessing the economic value of the losses associated with the use of new assets that form the distribution system or the economic value of the losses for comparing network design solutions. Guidance is provided on the network modelling and assessment of losses for individual assets (e.g. a system transformer), for project-specific network design solutions, where decisions are made by a design engineer on an individual project basis, and an asset class (e.g. low voltage cables), where decisions on asset standardisation are made at the policy stage. The application of this methodology will provide consistency and will inform the wider procurement and network design processes, to help comply with the losses related licence obligations. In addition, Northern Powergrid has obligations to report on the losses reduction to Ofgem via a variety of submissions including the Regulatory Reporting Pack, Environmental Report, Losses Strategy and Losses Discretionary Reward. Assessing the losses benefits from loss reduction strategies using this methodology will allow us to report on a consistent basis.

A final consideration is that it may be optimal, in terms of whole energy system losses and carbon reduction, to increase network losses to connect renewable generation near to load, such as via an active network management system.

3.3. Overview and Scope

3.3.1. Overview of distribution network losses

Distribution network losses can be broadly defined as the difference between the electrical energy entering the distribution network and the electrical energy exiting it, for consumption purposes and properly accounted for, in percentage terms for a particular period[5]. Losses are important because there is an environmental and economic cost associated with them. 'Environmental impacts' is one of the six primary output categories in Ofgem RIIO regulatory framework. The management of, and reduction in electricity losses, both technical and non-technical, are an objective of the regulatory framework. The framework consists of four elements in the

5 'CIRED WG CC-2015-2: Reduction of Technical and Non-Technical Losses in Distribution Networks'.

losses reduction mechanism to provide a strong input incentive for DNOs to manage losses efficiently: licence obligation, losses strategies, annual reporting and discretionary reward[6]. The economic reduction of losses is embedded within Northern Powergrid historical and existing asset procurement and network design policy decisions.

In the UK, losses account for about 5% to 6% of the total electricity entering the distribution networks[7]. Figure 1 is the total losses across Northern Powergrid Yorkshire licence area, depicting a similar percentage distribution on the Northeast licence and on other DNOs. It can be observed that the largest share of losses occur on the HV and LV systems, covering more than two-thirds of the total losses.

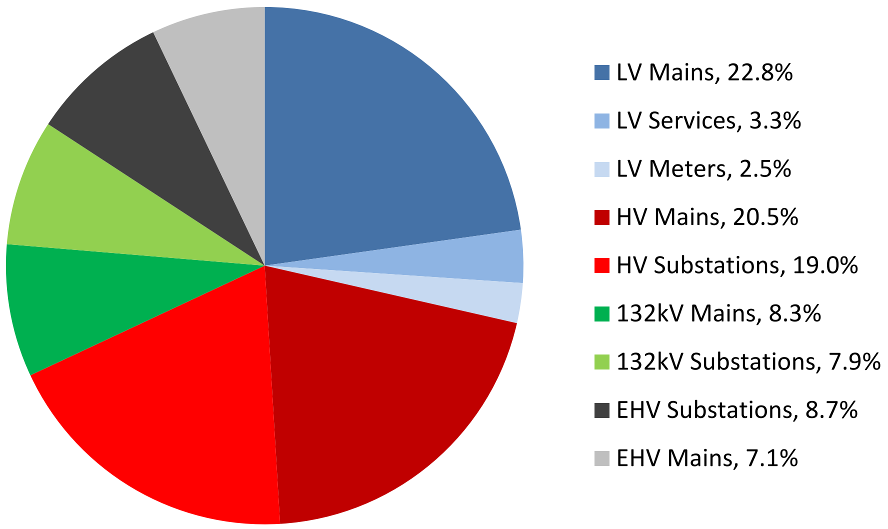


Figure 1: Typical overall distribution of percentage losses (adding up to 100%)[8]

3.3.2. Scope

In general, electrical losses can be categorised as shown in figure 2 and defined as below:

- Technical losses: Losses that occur naturally in power systems, associated with the passage of current through a resistance. This can be characterised as either:
    - Fixed losses: Losses that are incurred as a result of an asset being energised and are largely independent of network loading, contributing to roughly between a quarter and a third of the total technical losses on distribution networks.
    - Variable losses: Losses that are incurred directly as a result of load flowing through an asset, which are proportional to the load squared, contributing to roughly between two-thirds and three-quarters of the total power system technical losses.
- Non-technical losses[9]: Losses that are primarily related to unidentified, misallocated, and inaccurate energy flows, in which the end user is unknown or the amount of energy being consumed is uncertain[10]. These include theft and fraud in conveyance process and measurement errors.

6 Ofgem 'Guide to the RIIO-ED1 electricity distribution price control'.

7 It is reported in 'Electricity Distribution Systems Losses Non-Technical Overview', by Sohn Associates that the errors or measurement uncertainties attributed to up to 0.3% of the electricity distributed, which is up to about 6% of the losses themselves.

8 Northern Powergrid Strategy for losses, February 2018, version 2.1.

9 Internal Northern Powergrid policies related to Non-technical losses include: REG/008 – Policy in Respect of the Relevant Theft of Electricity, REG/008/001 – Code of Practice for the Investigation of Theft in Conveyance and REG/008/002 – Code of Practice for the Management of Unregistered Customers.

10 'CIRED WG CC-2015-2: Reduction of Technical and Non-Technical Losses in Distribution Networks'.

- Electrical energy consumed by network operations: For example the power consumption for heating and lighting at a substation.

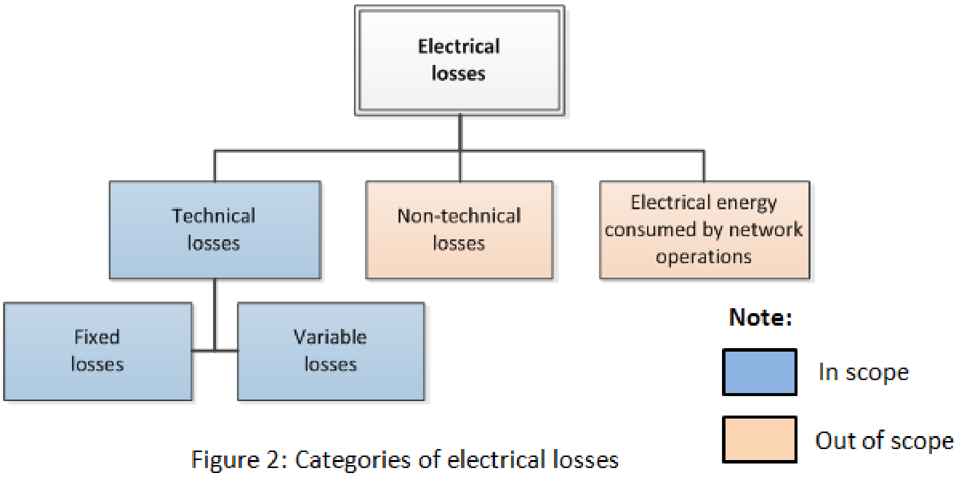


Figure 2: Categories of electrical losses

3.4. Losses Assessment Methodology

3.4.1. Northern Powergrid Losses Cost Benefit Analysis (CBA) Template

As part of the RIIO-ED1 process, proposed investments were assessed using Ofgem CBA spreadsheet. This spreadsheet enables the assessment of a wide range of investments and their avoided costs. Within the spreadsheet there are two categories which relate to losses, the cost of electricity used to supply the loss and the cost of CO_2 emitted to supply the loss.

The spreadsheet has been modified by Northern Powergrid at the following levels with an aim to balance financial investment to reduce losses and to include the cost or benefit of losses:

- Asset category/class: To assess the losses implications associated with alternative choices of asset
- Project level: To assess the losses implications associated with project-specific network design solutions.

This modified losses CBA template shall be used wherever there is a need to assess the losses associated with asset selection or network design solutions.

This modified CBA template can also be applied to determine the capitalised values for losses in the transformer procurement process. This is explained further in Appendix 6[11]. These values play a major role in selecting the most cost-effective and energy-efficient transformer to achieve an overall low transformer lifetime cost.

Where the options being considered are more complex it may be necessary to modify the template to suit the application, but this is outside the scope of this document.
Separate CBA templates have been designed for conductors, transformers, comparing network design solutions and for assessing transformer capitalised costs of losses. They are available in Northern Powergrid losses webpage (https://www.northernpowergrid.com/losses). These can also be found in the following links:

- Conductors;

11 These include iron loss values for all transformers and copper values for distribution transformers. System transformer copper loss values are to be calculated on a project basis. This is because specific units purchased for named sites contain detailed utilisation data to calculate the LLFs.

- Transformers;
- Design solutions; and
- Valuing the capitalised costs of losses for transformer procurement.

Section 3.4.2 below describes the methodology to calculate losses and to model the network, while Appendix 1 depicts a flowchart to summarise the losses assessment process to be inputted in the CBA template.

3.4.2. Losses Calculations

3.4.2.1. Fixed Losses

Fixed losses, also known as no-load losses, are incurred as a result of an asset being energised and are largely independent of network loading. This type of loss can therefore be calculated from the asset data.

Majority of fixed losses are caused by the energisation of transformers as a result of the alternating magnetic field applied to its iron core. These losses are also referred to as iron losses, and the value is provided by the transformer manufacturer. The alternating magnetic field produces losses in the iron core due to hysteresis, eddy currents and magnetostriction, dissipated both as heat and audible hum. The total fixed loss attributable to a transformer over a time period (e.g. one year), can be calculated by the following expression:

$$Total\ Fixed\ Loss\ =\ Iron\ Loss\ \times\ No\ of\ Hours\ in\ a\ Period \qquad (1)$$

The fixed loss for overhead lines is caused by corona discharge. However, this loss is negligible for overhead lines operating at voltage levels up to 275kV. The fixed loss for cables is a result of the alternating electric field being applied to the insulation used in the cable construction. It is the dielectric properties of the insulation that results in energy loss and this energy is lost mainly in the form of heat within the cable insulation. The fixed losses are negligible for cables operating at a voltage level of 20kV and below. Although the fixed losses for cables operating at 33kV and above are significant, the calculation is not applicable in this document. This is because the methodology in the CBA template to compare the losses benefits between two conductors is based on the assumption that the difference in fixed losses between them is negligible.

3.4.2.2. Variable Losses

Variable losses are incurred directly as a result of current flowing through a resistor which causes energy to be dissipated in the asset in the form of heat. Variable losses vary at each operating point in the network due to non-linear variations in network parameters and loading. The variable loss at any moment in time is equal to the Current^2 x Resistance (I^2R). The resistance mentioned in this document is always the positive-sequence resistance.

Due to the temporal dimension of network loading, load flow analysis ideally needs to be carried out each half hour (HH), usually covering a period of one year, in order to accurately calculate the variable loss on each asset. This can be simply expressed as:

$$Total\ Variable\ Loss\ in\ a\ Period = \sum\left(I_{HH\ loading}^2 \times R\right) \qquad (2)$$

However, since this approach is computationally complex, Loss Load Factor (LLF) can be applied to simplify the variable loss calculations without compromising its accuracy.

LLF is a variable loss factor allowing the fact that the asset is not operating at the maximum load condition continuously within any given time period, and therefore not contributing to losses on a consistent basis. In other words, it is the 'Load Factor' of losses.

The total variable loss (in kWh) for a given asset over a time period of one year can therefore be summarised in the expression below[12]:

$$Total\,Variable\,Loss\,in\,a\,Year\;=\;Sum\,of\,each\,HH\,Loss\,in\,a\,Year$$

$$=\;Average\,Power\,Loss\;\times\;No\,of\,Hours\,in\,a\,Year$$

$$=\;Peak\,Loss\,during\,the\,Year\;\times\;LLF\;\times\;8766 \qquad (3)$$

Equation (3) forms the basis of the variable losses calculations on the CBA template. Only two values need to be determined to obtain the total variable loss, i.e. the peak loss and LLF. The peak loss are either calculated or obtained, depending on the type of the CBA template. For the conductor template, users need to input the peak current or maximum demand (in Amp) per phase and the resistance (in Ohm) of the asset to be assessed, and the template will calculate the peak loss value. For the transformer template, users only need to input the copper loss at ONAN rating from the transformer manufacturer datasheet in Watt (W) or kiloWatt (kW) as well as determining the transformer utilisation, and the template will calculate the peak loss. For the design solution template, the peak loss is obtained from DINIS/IPSA simulation results in kiloWatt (kW). Users also need to obtain the LLF value either by calculations using actual measured or predicted data or by using a generalised value. This is explained further in section 3.4.3, followed by various examples in the appendices of this document. The definition and concept of LLF, as well as Load Factor (LF), will be explained in the following section.

3.4.2.3. Loss Load Factor (LLF)

LLF is defined as the ratio between the average loss over a time period and the peak loss during that time period:

$$LLF = \frac{P_{Lavg}}{P_{Lpeak}} \qquad (4)$$

$$P_{Lavg} = \frac{\sum_{n=1}^{T}(I_n^2 \times R)}{T} \qquad (5)$$

$$P_{Lpeak} = \left(I_{peak}\right)^2 \times R \qquad (6)$$

where

P_{Lavg} = Average power loss in kW, over a time period

P_{Lpeak}= Peak loss in kW, during that time period

I_n = Loading in A, at HH number n

I_{peak} = Loading at maximum demand, or peak loading, in A

n = HH number

R = Resistance of the asset

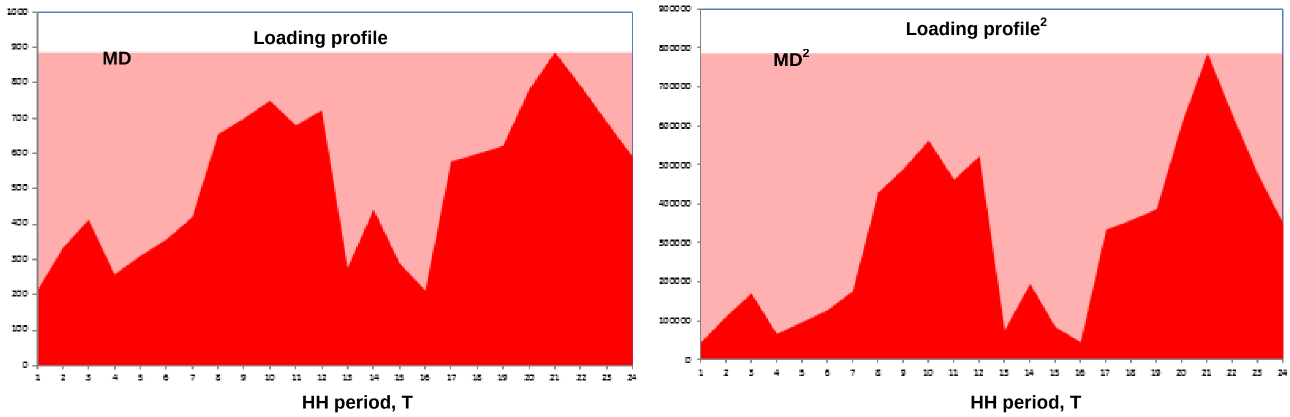
T = Total HH in a period

12 Derivation to obtain equation (3) is shown in Appendix 2.

From equations (4), (5) and (6), and assuming resistance of the asset and system voltage are constant, LLF can also be expressed as:

$$LLF = \frac{\sum_{n=1}^{T}(HH\ loading_n^2)}{T \times (MD)^2} \qquad (7)$$

The HH loading and MD (maximum demand) is in kVA. Thus, the LLF of an asset can be obtained from its loading profile, which is graphically represented in figure 3 below for a 24 HH period, T, which is equivalent to a 12 hour period.



(a) (b)

Figure 3: (a) HH loading profile showing peak value or Maximum Demand
(b) Equivalent profile of the loading^2 and the peak value^2 (MD^2)

It can be observed in figure 3(b) that the loading profile^2 accentuates the peaks and troughs of its loading profile in figure 3(a), which is a reflection of the characteristics of variable losses with respect to the loading of the asset. The area under loading profile^2 graph (the red area) also represents the numerator in the LLF equation (7). Similarly, the rectangular pink area (MD^2), partly obscured by the red area in the same graph, represents the denominator in equation (7). LLF can be visualised as the ratio of these two areas respectively and therefore can easily be computed.

Load Factor (LF) is defined as the ratio between the average load over a time period and the peak load during that time period:

$$LF = \frac{P_{avg}}{P_{peak}} \qquad (8)$$

$$= \frac{\sum_{n=1}^{T}(HH\ loading_n)}{T \times (MD)} \qquad (9)$$

P_{avg} = Average loading in kW, over a time period

P_{peak}= Peak loading in kW, during that time period

Similar to LLF, LF can also be visualised as the ratio between the red and the pink areas of figure 3(a). Several empirical equations exist to derive LLF based on LF. However, due to inaccuracies in the approximations, and since losses are proportional to the LLF and therefore sensitive to it, these empirical relationships will not be discussed further. Where possible, LLFs should therefore be derived accurately and directly from the HH loading profile using equation (7).

Figure 3 above shows a positive (import) loading profile. In a situation when generation (export) is present on a network and the generation exceeds load, the power flow will change direction and the loading profile will become negative. Since it is the magnitude of power flow and not its direction that governs the variable loss, it is important that the MD value is correctly identified, and the MD^2 value is derived from the largest positive, as depicted in figure 4 for a per-unitised loading profile and the equivalent loading $profile^2$.

Figure 4 also illustrates another important point, i.e. LLF is always less than LF, by observing that the area under the graph for loading $profile^2$ shrinks as compared to the loading profile. If LLF is equal to LF, the load profile might be constant or bimodal (e.g. heat pump and battery storage), where the load is either zero or a fixed value. It can also be deduced that the LF and LLF give some indication on the characteristics of the load profile. A more uniform load profile has higher LF and LLF values than a less uniform and more 'peaky' load profile.

For a network configuration where a load profile is unavailable, table 1 provides a guideline[13] for the LLF on different assets and network which can be used in the methodology. For a network configuration where a generation export profile should be used instead of a load profile, if the profile is unavailable, table 2 provides a guideline for the LLF of typical generation types which can be used in the methodology[14]. Appendix 2 in this document provides examples of LLF calculations.

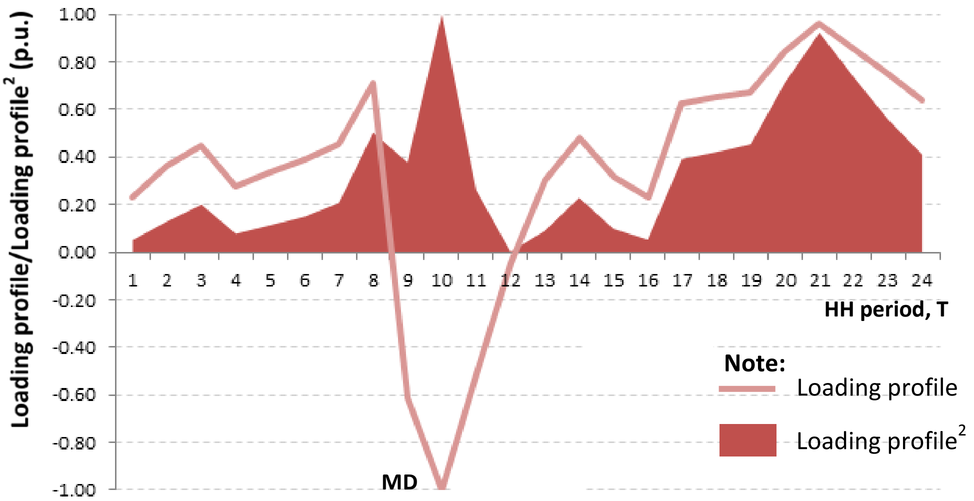


Figure 4: Illustration on the impact of generation on LLF calculation. Per-unitised loading profile is superimposed on its equivalent loading $profile^2$.

13 Table 1 is derived from CLNR smart metering data and PI . It is discussed in more detail in Appendix 5.

14 Table 2 is derived from PI, guided by the Northern Powergrid generation availability map (https://www.northernpowergrid.com/generation-availability-map). For a generation type not included in this table, a comparable generation profile can be identified from the map and its profile can extracted from PI. Advice can also be sought from the Smart Grid Implementation Unit.

Asset[15]	LLF
Service equipment	0.05
LV mains and pole-mounted transformers	0.15
Ground-mounted transformers	0.225
HV feeders only	0.25
HV assets and network (excluding HV feeders)	0.36
EHV assets and network	0.42

Table 1: LLF values on network assets where a load profile is unavailable

Generation type	LLF
Solar	0.06
Onshore windfarm	0.18
Biomass	0.38
Landfill gas, sewage gas and biogas	0.28
Waste incineration (not CHP)	0.51
Hydro run-off river and poundage	0.19

Table 2: LLF values on network assets where a generation profile is unavailable

3.4.2.4. Network Modelling for Asset-specific Losses Assessment

This purpose of this section is to provide guidance into identifying the loading profiles for LLF calculations when assessing the variable losses of specified assets for different network configurations, as part of the requirement for the CBA template. There are some instances where aggregation of different loading or generation profiles will be required instead of just observing a single profile. This is why the network and the loading conditions need to be modelled and determined correctly to calculate the likely current flowing through each asset. As explained in section 3.4.2.1, the modelling assumption in this document is such that the fixed losses of conductors can be ignored. It is also worth noting that the load profile at a substation should be used instead of individual transformer analogues to avoid inaccurate result, taking into account the scenario of load transfer when one transformer is temporarily out of service (e.g. due to maintenance).

15 The HV and EHV assets and network LLF values should only be applied when i) carrying out generic losses assessment where no particular HV or EHV network is chosen ii) introducing a new network (e.g. a new primary for a new development).

3.4.2.5. Simple Network

Figure 5 is a simple network highlighting the assets and associated losses to be considered to calculate the correct values of loss of the assets.

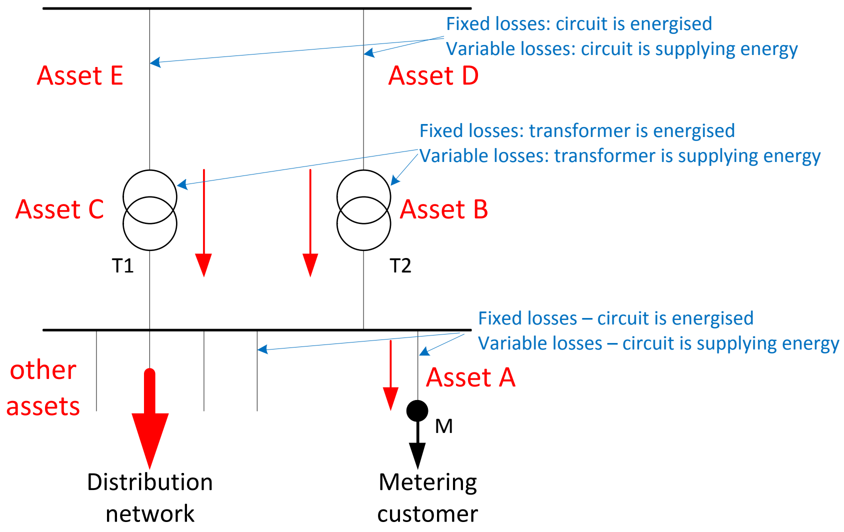


Figure 5: Simple network model

Asset A
This asset supplies only the metered demand customer and hence the load profile seen by the asset is that of the customer. The calculation model will therefore assign the customer load profile to this asset.

Asset B
This asset normally operates in parallel with Asset C to share the load recorded at the substation. Normally transformers in such a case will share the load equally and hence a load profile of 50% of that recorded at the site is assigned to the transformer. If necessary, a load flow may be carried out using Northern Powergrid approved electrical modelling software (IPSA or DINIS), to confirm the percentage of load-sharing between the two assets (ignoring any load transfers during outages).

Asset C
This will be the same as for Asset B.

Asset D
This asset is used to supply load to Asset B, hence the loading profile assigned to this asset will be the same as that assigned to Asset B.

Asset E
This asset is used to supply load to Asset C, hence the loading profile assigned to this asset will be the same as that assigned to Asset C.

Other Assets
For EHV distribution network, loading profile data for existing assets should be available and losses should therefore be individually assessed. When loading profile data is not available (usually on HV, LV and entirely new networks), LLF values on table 1 can be used to assess the losses of an asset. If the circuit configuration is simple and load data is available, then, the appropriate modelling method as explained in section 3.4.2.3 can be used to obtain more accurate results.

3.4.2.6. Simple Network with Generation

Figure 6 depicts the same simple network as in figure 5, but now with generation at the same site.

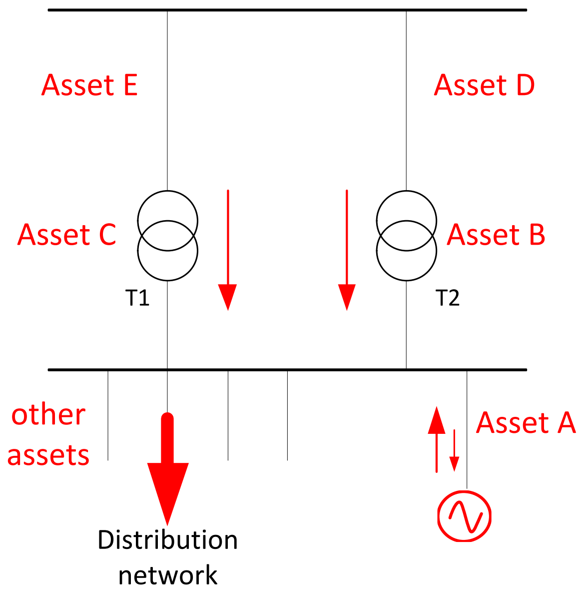


Figure 6: Simple Network with Generation

Asset A
Depending on the characteristics of the generation, the size of its import profile can vary compared to the export profile. Thus, the initial stage of the assessment is to validate whether the import is significantly lower (i.e. less than 10%) than the export, such that it can be ignored. On the other hand, if the import profile needs to be considered, the total loss for the asset is the sum of losses during both import and export.

Asset B
The loading recorded at the substation is the net demand at the substation. It includes any generation present on the network and therefore directly reflects the loading profile required. Thus the logic for determining the load profiles for Asset B, C, D, E and other assets is the same as described in section 3.4.2.3.1.

3.4.2.7. Complex Network

A more complex network may contain tee offs to other substations, having a closed-ring configuration or multiple in-feeds to the same point. In either of these cases the network feeding arrangement has to be fully understood and taken account of to determine the correct loading and power flow on circuit assets. Figure 7 shows an example of this complex network. The loading on Asset C is influenced by the loading on Asset A and Asset B and hence this needs to be taken into account of in order to derive the correct load on Asset C.

The load profile for Asset C is derived by summing the half load profiles of Substation A and Substation B. Normally, the transformers at Substation A and Substation B share the load equally i.e. 50-50. If necessary, a load flow may be carried out using IPSA or DINIS to confirm the direction of the power flow and the percentage of load-sharing between the two assets in both substations.

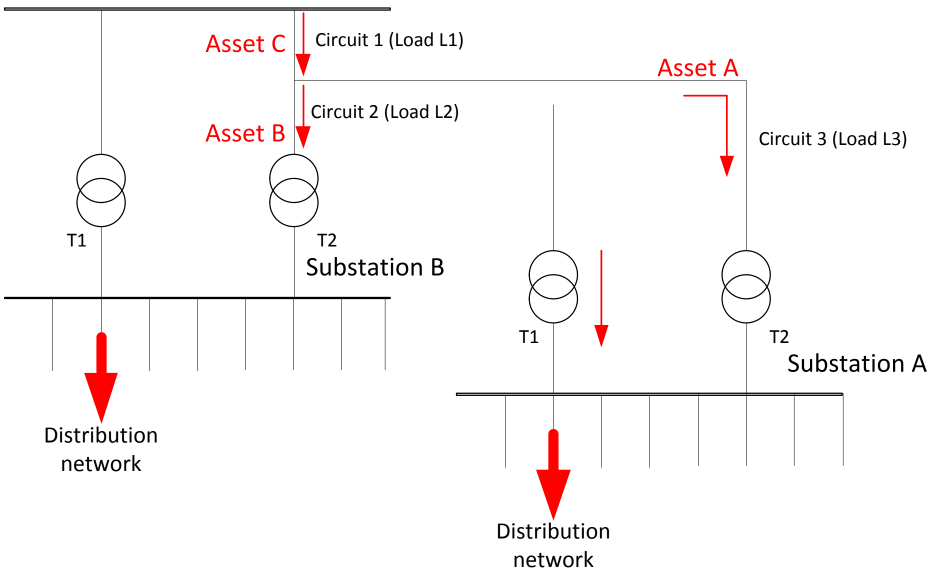


Figure 7: Complex Network

3.4.2.8. Complex Network with Generation

In figure 8, the same rule as described in section 3.4.2.3.3 is applied for a complex network with generation, taking into account the impact of reverse power flow by the generation.

If it is assumed that the transformers at Substation A share the load equally, the load profile for Asset C is derived by the net flow of the half of load profile of Substation A and the generation net export profile. If necessary, a load flow may be carried out using IPSA or DINIS to confirm the percentage of load-sharing between the two assets in Substation A. Similar to the scenario explained in section 3.4.2.2.1 for figure 4, in a situation where the generation exceeds the load, the power flow will change direction and the loading profile of Asset C will become negative. Since it is the magnitude of power flow and not its direction that governs the variable loss, it is important that the MD value is determined correctly. An example of this is shown in section A3.2 of Appendix 3.

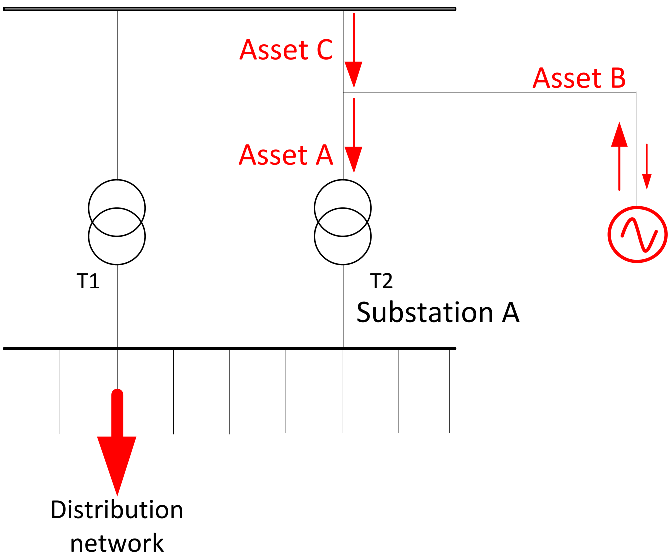


Figure 8: Complex Network with Generation

3.4.2.9. Network Modelling for Design Solution Losses Assessment

For HV and EHV network, losses should be taken into consideration as part of the design process by embedding the lifetime benefit (or cost) of losses in the design cost. The design process is summarised in the flowchart of Appendix 1, and is generally classified into three, as described below:

3.4.2.10. Asset Replacement and Reinforcement

Assessing losses CBA for asset replacement and reinforcement that do not alter the configuration of the existing network is straightforward as it directly follows the method presented in section 3.4.2.3 for asset-specific losses assessment, with examples presented in Appendix 2, 3 and 5.

3.4.2.11. Network Reconfiguration

Reconfiguring the network will lead to power flows which are different from historical flows. The change in network loading and the impact on losses will therefore vary, depending on the location and the extent of the reconfiguration, whether or not any new assets are to be introduced or any existing assets are to be made redundant. For example, to assess the losses cost or benefit of a normal open point (NOP) change in a primary network, only obtain the losses related to relevant feeders from the load flow result in DINIS before and after the change. For a more extensive network reconfiguration, obtain the losses of the whole network from the load flow results in DINIS or IPSA model for baseline (pre-design) and proposed (post-design) option. If more than one network is involved, for example load transfer to an adjacent primary, assess both primaries individually, calculate the net lifetime benefit or cost of losses of both primaries and include this value into the overall cost of the design. To simplify the analysis, it is sensible to assume that the change in network loading does not distort the shape of its profile as a result of the reconfiguration. Thus, the relevant LLF for the pre-reconfigured network can be used. An example of a losses assessment of a design to split the load of a primary network is presented in Appendix 7.

3.4.2.12. New Connection

A new load or generation connected to the network will also lead to power flows which are different from historical flows. The change in network loading and the impact on losses will also vary, depending on the size of the background network loading and the new connection, as well as the location and characteristics of the new connection.

- **Generation:** Determine the fixed and variable losses from the load flow result of the DINIS/IPSA model before and after connecting the generation. Consider the worst case from either maximum or minimum network demand scenario, i.e. the least net losses benefit or the highest net losses cost. For a generation type listed in table 2, an aggregated generation LLF curve in section A7.2 of Appendix 7 can be used as a guidance to obtain the aggregated LLF by following the steps shown in the flowchart of Appendix 1[16]. The aggregated generation LLF curve assumes a typical network with an LLF of 0.36.
- **Load:** Determine the fixed and variable losses from the load flow result of the DINIS/IPSA model before and after connecting the load. Obtain the anticipated load profile for one year and calculate the aggregated LLF of the load with the connected network[17].

16 For other generation type, a comparable generation profile can be identified from the Northern Powergrid generation availability map (https://www.northernpowergrid.com/generation-availability-map) and its profile can extracted from PI. Advice can also be sought from the Smart Grid Implementation Unit.

17 with the aid of the Northern Powergrid Distribution Load Estimate (DLE) and Northern Powergrid demand availability map (https://www.northernpowergrid.com/demand-availability-map). The load profile can be extracted from PI. Advice can also be sought from the Smart Grid Implementation Unit.

3.4.3. Whole Life Losses Assessment

As mentioned in section 3.4.1, the CBA template requires the user to input the losses values. Section 3.4.3.1 and 3.4.3.2 below describe how these losses should be calculated for both conductors and transformers respectively, while 3.4.3.3 explains the losses calculations for design solution. A load growth factor has been included in the assessment and can be used to adjust the losses over the asset life for different load growth scenarios, however care must be taken to ensure the projected load on the asset does not exceed the capability of the asset before end of the 45 year losses assessment period; in such a scenario the assessment period should be limited to the period until the projected load equals the capability of the asset. The CBA template also allows user to input up to three terms, i.e. years from the installation year, including the design solution life expectancy. Section 3.4.3.4 briefly describes the net present value (NPV) calculations.

A flowchart in Appendix 1 shows the process of assessing losses and which parameters to consider.

3.4.3.1. Conductors (Overhead Lines and Cables)

The main contributing factor to overall losses in conductors (cables and overhead lines) is the variable losses, so the dominant component is the I^2R losses. As explained in section 3.4.2.1, the difference in fixed losses (no-load losses) between two conductors is negligible.

From equation (3) and (6), the total variable loss in a year incurred in the each conducting core of the asset is given by the following expression:

$$Total\,Variable\,Loss = I_{Peak}^2 \times R \times LLF \times 8766 \tag{10}$$

Where

I_{peak} = *Peak current (in A) of the conductor (under normal operating conditions)*

R = Per kilometre phase resistance (in Ohms) of the conductor[18]

This gives the total loss in Watt-hours per kilometre per phase.

The CBA template provides flexibility in terms of the conductor phase (single, 2-phase or 3-phase), assuming that the load is balanced. It can also model a uniformly distributed load along the feeder by introducing a factor known as the Feeder Loss Factor (FLF). The user must decide how many load points are on the particular feeder in the spreadsheet. The theory behind the FLF concept for assessing losses is shown in Appendix 4. Examples of conductor calculations are shown in Appendix 3.

3.4.3.2. Transformers

Total transformer loss is the sum of its fixed loss (also known as no-load loss, or iron loss) and variable loss (copper loss).

Transformer fixed loss is described in section 3.4.2.1. Applying equation (1) gives the following expression for total fixed loss in a year:

$$Total\,Fixed\,Loss = Iron\,Loss \times 8766 \tag{11}$$

18 It is recommended to use the AC resistance value at the conductor's maximum operating temperature to take into account the skin effect.

The variable loss is incurred in the windings of the transformer which are traditionally manufactured from copper and hence variable transformer losses are often referred to as copper losses. Applying equation (3) for total variable loss in a year gives the following expression:

$$Total\ Variable\ Loss = Transformer\ Copper\ Loss \times Utilisation^2 \times LLF \times 8766 \qquad (12)$$

Where

$$Utilisation = \frac{Transformer\ maxium\ demand}{Transformer\ ONAN\ rating} \qquad (13)$$

The peak loss for transformer is determined by its copper loss and utilisation. The transformer copper loss is the measured copper loss at a stated ONAN rating (in Watts) and can be found on the test certificate provided by the manufacturer. This result gives the total variable losses in Watt-hours. The CBA template provides flexibility in terms of allowing more than one transformers to be compared, for example to calculate the CBA of replacing 3 x 45 MVA system transformers with 2 x 60 MVA on a site.

Examples of transformer losses calculations are shown in Appendix 5. These examples illustrate the lifetime benefit of installing a more expensive but lower loss transformer.

This assessment applies the following assumptions:

- The resistance of the transformer windings remains constant through its loading cycle;
- If more than one transformers are assessed, they are identical and load is split evenly between the transformers;
- The asset is operating in its normal operating condition (e.g. a primary substation is normally operated with two transformers in parallel such that each transformer operates within its ONAN rating). It is assumed that the increase in losses in an outage (e.g. OFAF/OFAN/ONAF), although on a daily basis may be much higher than normal conditions, over the course of a year is not significant; and
- The maintenance cost for both compared assets is the same and is not included in the analysis.

3.4.3.3. Design Solution

The CBA template also enables the losses associated with different design solutions to be calculated so that losses can be considered in the decision making process by including the cost or benefit of losses in the overall cost of the design. The variable (load) and fixed (no-load) losses can be derived from DINIS or IPSA models and be used as inputs to the template.

3.4.3.4. Net Present Value (NPV) Calculations

NPV calculations are carried out within the CBA template and are not discussed in detail here. The template populates the original Ofgem CBA spreadsheet with both the expenditure profile (assumed to be a single capital investment on year one) and the losses profile over the life of the asset (assumed to start in year two for the asset life). Costs and benefits to be considered in the CBA are those that would occur over and above the baseline scenario. These additional costs and benefits represent the marginal or incremental costs or benefits of the option being considered.

When the losses figure and expenditure have been inputted, the template calculates the NPV. All negative impacts of an option are classified as costs and all positive impacts as benefits. If the NPV is positive before the end of the asset life (or the expected lifetime of the solution), the investment is considered worthwhile.

The following financial and regulatory assumptions have been made in this methodology for assessment of losses:-

- The power sector will become 'decarbonised' by 10g/kWh per year until 2050
- The cost of carbon will rise in line with DECC predicted carbon values
- The cost of losses is £48.52/MWh (2012/13 prices)
- Pre-tax Weighted Average Cost of Capital (WACC) for Northern Powergrid is assumed 3.7%
- The asset life is 45 years
- The capitalisation rate is assumed 70%[19].

19 The capitalisation rate is 72% in Northern Powergrid Yorkshire and 70% in Northeast, however a rounded figure of 70% is used as default.

4. References

4.1. External Documentation

Reference	Title
A paper prepared for Ofgem by Sohn Associates Limited	Electricity Distribution Systems Losses Non-Technical Overview
CIRED WG CC-2015-2	Reduction of Technical and Non-Technical Losses in Distribution Networks
Ofgem website	Guide to the RIIO-ED1 electricity distribution price control
The Act	The Electricity Act 1989 (as amended by The Utilities Act 2000 and The Energy Act 2004 and The Energy Act 2004 (Amendment) Regulations 2012 (No. 2723, 2012)
The Distribution Code	The Distribution Code of Licensed Distribution Network Operators of Great Britain
The Electricity Distribution Licence	Standard conditions of the Electricity Distribution Licence

4.2. Internal Documentation

Reference	Title
Northern Powergrid losses cost-benefit assessment (CBA) template	1. NPg Losses CBA Template Capitalised Loss Transformers.xlsx 2. NPg Losses CBA Template Conductor.xlsx 3. NPg Losses CBA Template Design Solution.xlsx 4. NPg Losses CBA Template Transformer.xlsx
Version 1.1	Guidance for the Calculation of Site Specific Loss Adjustment Factors
Version 2.1	Strategy For Losses. Downloadable from https://www.northernpowergrid.com/losses

4.3. Amendments from Previous Version

Reference	Description
Appendix 6	Iron loss and copper loss values updated according to the latest WACC value of 3.7%
Northern Powergrid losses cost-benefit assessment (CBA) template	Capitalised Loss Transformers template on the losses webpage https://www.northernpowergrid.com/losses updated according to the latest WACC value of 3.7% and the instructions on the 'NPg Data Input' tab on the template updated.
Section 3.4.3.4	Pre-tax weighted Average Cost of Capital (WACC) updated to 3.7%

5. Definitions

Term	Definition
CBA	Cost Benefit Analysis
CLNR	Customer Led Network Revolution
DECC	The Department of Energy & Climate Change
DINIS	Distribution Network Information System. System Studies Software
Distribution transformer	HV/LV transformer
DNO	Distribution Network Operator
EHV	Extra High Voltage. Voltage equal to or greater than 33kV and less than 132kV
FLF	Feeder Loss Factor. A function of the number of point load in a feeder, to obtain the losses as a result of the distributed demand.
HH	Half-hour
HV	High Voltage. Voltage greater than 1kV and less than 33kV
I^2R	A derivation of Ohm's law describing the energy lost via heat generated from the passage of current through a resistor.
IPSA	Interactive Power System Analysis. System Studies Software
LF	Load Factor. Ratio between the average load over a time period and the peak load during that time period
LLF	Loss Load Factor. Ratio between the average loss over a time period and the peak loss during that time period
LV	Low Voltage. Voltage up to and including 1000V
MD	Maximum demand
Northern Powergrid (NPg)	Northern Powergrid (Northeast) plc. and Northern Powergrid (Yorkshire) plc.
NPV	Net Present Value
OFAF	Oil Force Air Force
OFAN	Oil Force Air Natural
Ofgem	The Office of Gas and Electricity Markets, or its successor
ONAF	Oil Natural Air Force
ONAN	Oil Natural Air Natural
PI	Plant Information. Software modules designed for plant-wide monitoring and analysis
RIIO-ED1	Revenue = Incentives + Innovation + Outputs; Electricity Distribution period 1
System transformer	132/EHV, 132/HV and EHV/HV transformer
Utilisation	Ratio of plant load against plant rating
WACC	Weighted Average Cost of Capital

6. Authority for Issue

6.1. CDS Assurance

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

		Date
Dan Rodrigues	Governance Analyst	12/08/2020

6.2. Author

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

Review Period - This document should be reviewed within the following time period.

Standard CDS review of 3 years?	Non Standard Review Period & Reason	
Yes	Period: n/a	Reason: n/a
Should this document be displayed on the Northern Powergrid external website?		Yes
		Date
Aisha Ahmad	Smart Grid Development Engineer	12/08/2020

6.3. Technical Assurance

I sign to confirm that I am satisfied with all aspects of the content and preparation of this document and submit it for approval and authorisation.

		Date
Phil Jagger	Design Team Manager	24/08/2020

6.4. Authorisation

Authorisation is granted for publication of this document.

		Date
Mark Nicholson	Head of Smart Grid Implementation	13/08/2020

Appendix 1 – Losses Assessment Flowchart

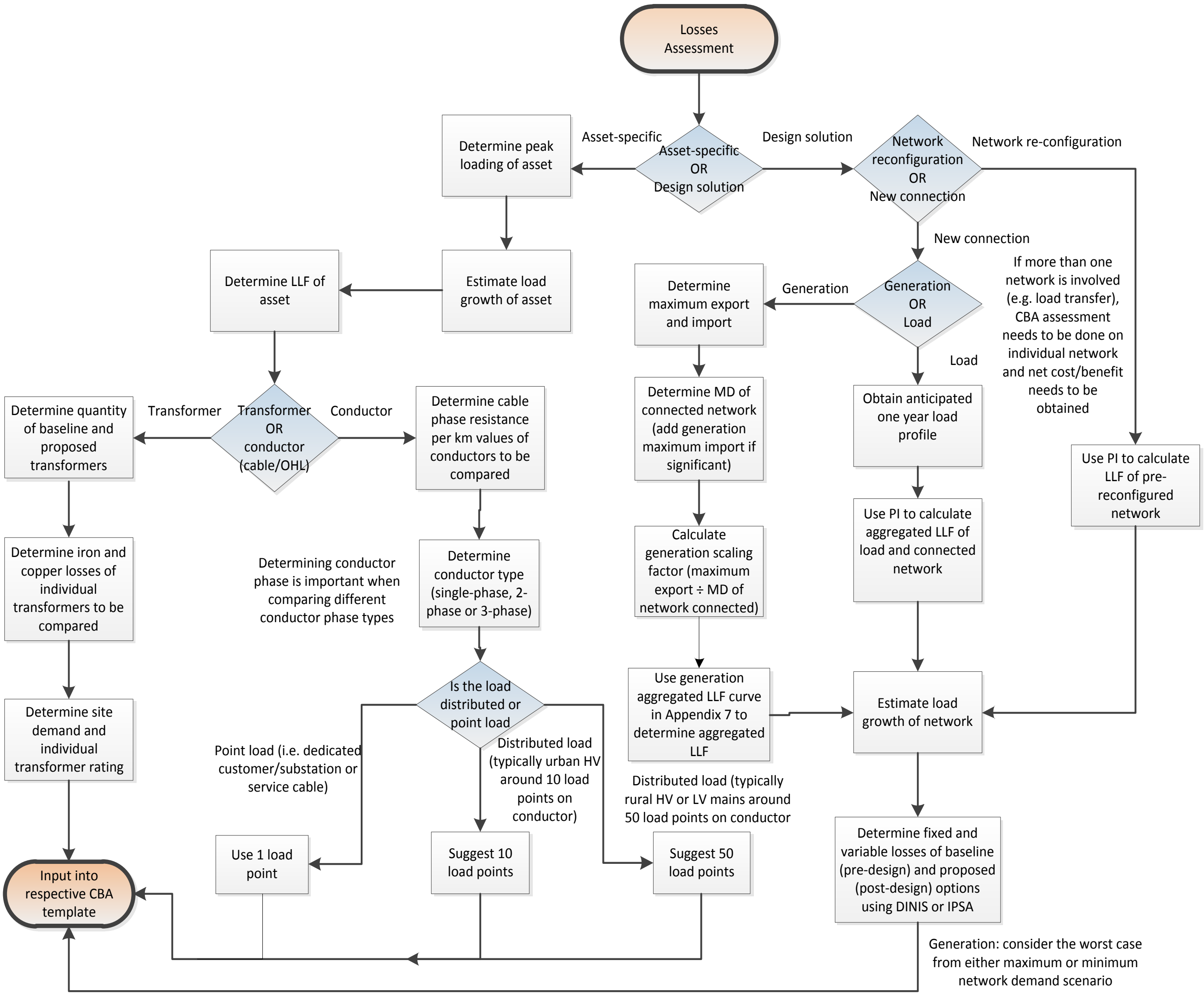


Figure A1.1: Losses Assessment Flowchart

Appendix 2 – Loss Load Factor (LLF): Calculations and Derivation

A2.1) LLF Calculation: Example 1

This example shows a simple worked example for an asset having a resistance of 2 ohms and associated HH loading profile for a period of 24 HHs. If it is connected at a voltage of 230 volts, then the losses can be calculated by two methods below. This illustrates the difference in complexity whilst confirming the same result of 143.45kWh of loss in the period. Method 1 requires loss value every HH. In method 2, the total variable loss on each asset, over a given period of time, is calculated from the maximum demand, the LLF, the electrical resistance properties of the asset and the number of hours in the period, as shown in figure A2.1:

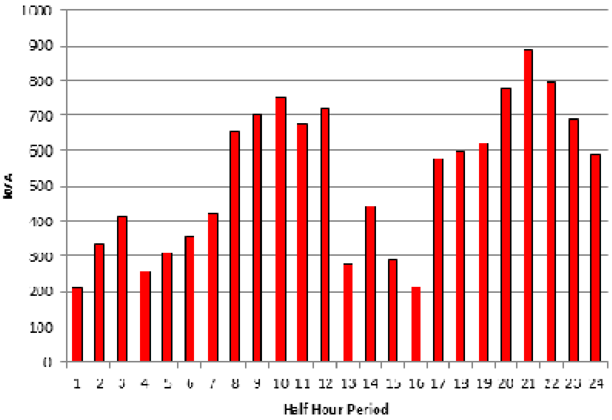


Figure A2.1: Asset Loading

HH Period	Loading		Loss	
	kVA	I (A)	kW	kWh
1	210	0.91	1.67	0.83
2	333	1.45	4.19	2.10
3	413	1.80	6.45	3.22
4	258	1.12	2.52	1.26
5	311	1.35	3.66	1.83
6	357	1.55	4.82	2.41
7	420	1.83	6.67	3.33
8	655	2.85	16.22	8.11
9	700	3.04	18.53	9.26
10	750	3.26	21.27	10.63
11	680	2.96	17.48	8.74
12	723	3.14	19.76	9.88
13	277	1.20	2.90	1.45
14	442	1.92	7.39	3.69
15	290	1.26	3.18	1.59
16	213	0.93	1.72	0.86
17	578	2.51	12.63	6.32
18	599	2.60	13.57	6.78
19	622	2.70	14.63	7.31
20	780	3.39	23.00	11.50
21	**887**	**3.86**	**29.75**	**14.87**
22	792	3.44	23.72	11.86
23	690	3.00	18.00	9.00
24	591	2.57	13.21	6.60

Total power loss = 143.45 kWh

Table A2.1: Method 1: Calculations of loss on every HH

Method 2: Calculations using LLF:

No of HH, T = 24
No of hours = 12
Max demand (MD) = 887
Max current = 3.86

Recall equation (7) and (9)

$$LLF = \frac{\sum_{n=1}^{T}(HH\ loading_n^2)}{T \times (MD)^2} = 0.40188 \qquad \text{(A2.1)}$$

$$LF = \frac{\sum_{n=1}^{T}(HH\ loading_n)}{T \times (MD)} = 0.59 \qquad \text{(A2.2)}$$

Total power Loss = I^2 x R x LLF x Hours
= 3.86^2 x 2 x 0.40 x 12
= **143.45 kWh** (A2.3)

A2.2) LLF Calculation: Example 2

Figure A2.2 is the load profile for a year at North Avenue primary substation. The maximum demand MD (obtained from Northern Powergrid DLE) = 11300 kVA. From equation (A2.1):

$$LLF = \frac{\mathbf{6.77448(10^{11})}}{\mathbf{17532 \times (11300)^2}}$$

$$= \mathbf{0.3} \qquad \text{(A2.4)}$$

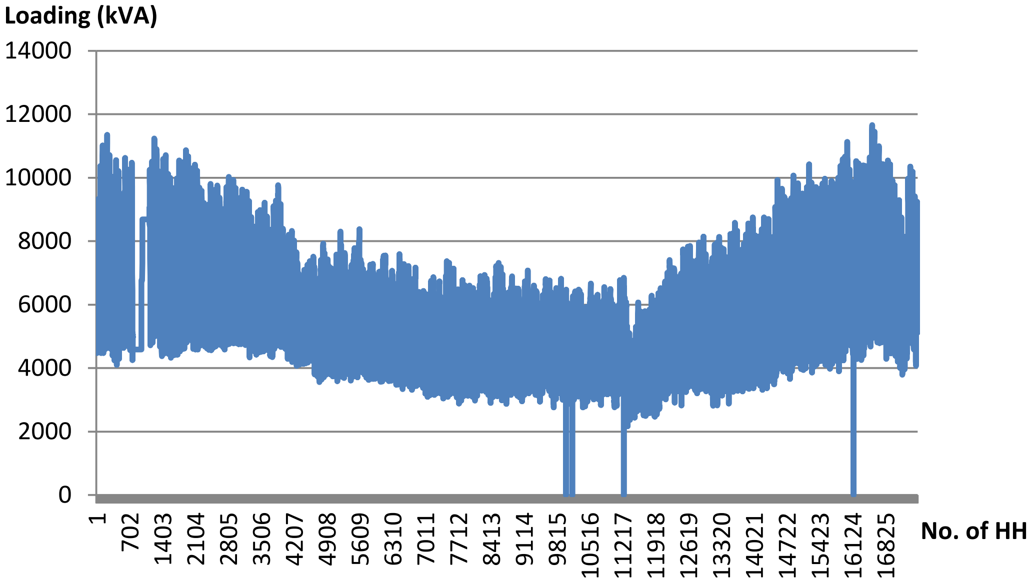


Figure A2.2: North Avenue load profile for a year

A2.3) LLF Calculation: Example 3

Figure A2.3 and equation (A2.5) shows LLF calculation of an aggregated profile of North Avenue Primary and Pool Primary:

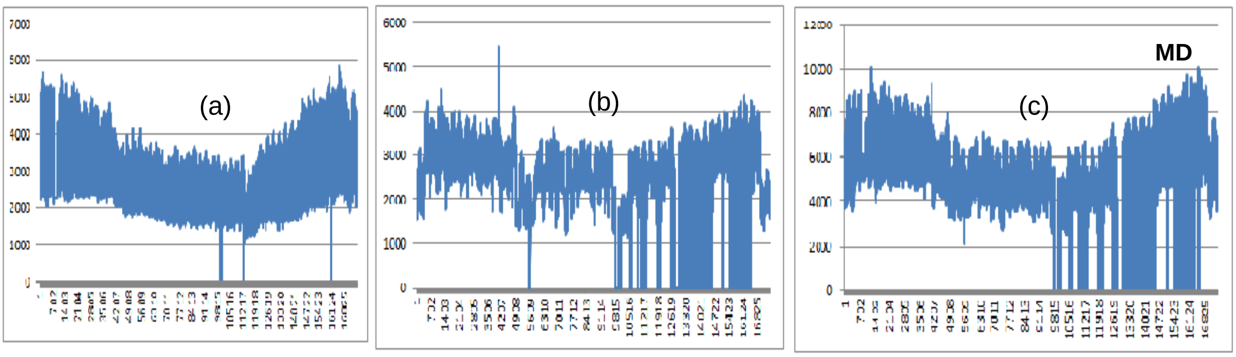


Figure A2.3: (a) Half of load profile for North Avenue
(b) Half of load profile at Pool
(c) New (aggregated) load profile for LLF calculation

$$New\ (aggregated)\ load\ profile = \left(\frac{1}{2} \times Load_{North\ Avenue}\right) + \left(\frac{1}{2} \times Load_{Pool}\right) \qquad \text{(A2.5)}$$

New MD from figure A2.3(c) = 10,000kVA

Thus, LLF for the new aggregated load profile = **0.34** (A2.6)

A2.3) Derivation of Total Variable Losses Calculations applying LLF

This section will show how total losses calculation, which is the sum of each HH loss in a time period, can also be expressed as a product of peak loss, LLF and the time period.

Total variable loss in a HH period *T* = Sum of each HH loss in the time period:

$$\sum_{n=1}^{T} losses_{kWh} = \frac{1}{2} I_1^2 \times R + \frac{1}{2} I_2^2 \times R + \cdots + \frac{1}{2} I_T^2 \times R \quad \text{(A2.7)}$$

For a three phase network, assuming constant voltage *V* and resistance *R*,

$$\sum_{n=1}^{T} losses_{kWh} = \frac{\frac{1}{2} \times R \times (3 \times V)^2 \left[I_1^2 + I_2^2 + \cdots + I_T^2 \right]}{(3 \times V)^2}$$

$$\sum_{n=1}^{T} (HH\ loading_n^2) = (3 \times V)^2 \times \sum_{n=1}^{T} I_n^2 \quad \text{(A2.8)}$$

Substituting (A2.8) into (A2.7):

$$\sum_{n=1}^{T} losses_{kWh} = \frac{\frac{1}{2} \times R \times \sum_{n=1}^{T} (HH\ loading_n^2)}{(3 \times V)^2}$$

$$= \frac{\frac{1}{2} \times I_{max}^2 \times R \times \sum_{n=1}^{T} (HH\ loading_n^2)}{(3 \times V \times I_{max})^2} \quad \text{(A2.9)}$$

$$Peak\ loss_{kWh} = I_{max}^2 \times R \quad \text{(A2.10)}$$

$$\frac{Number\ of\ hour}{Number\ of\ HH} = \frac{1}{2} \quad \text{(A2.11)}$$

Maximum demand

$$MD = 3 \times V \times I_{max} \quad \text{(A2.12)}$$

Recalling LLF expression in equation (7) of section 3.4.2.2.1 in the document:

$$LLF = \frac{\sum_{n=1}^{T} (HH\ loading_n^2)}{T \times (MD)^2} \quad \text{(A2.13)}$$

Substituting (A2.10) to (A2.13) into (A2.9) gives the same variable losses for the asset as obtained in equation (A2.7), for a year:

$$\sum_{n=1}^{T} losses_{kWh} = Peak\ loss_{kWh} \times LLF \times 8766 \quad \text{(A2.14)}$$

Appendix 3 – Conductor Losses Examples

A3.1) Example 1: Simple Network

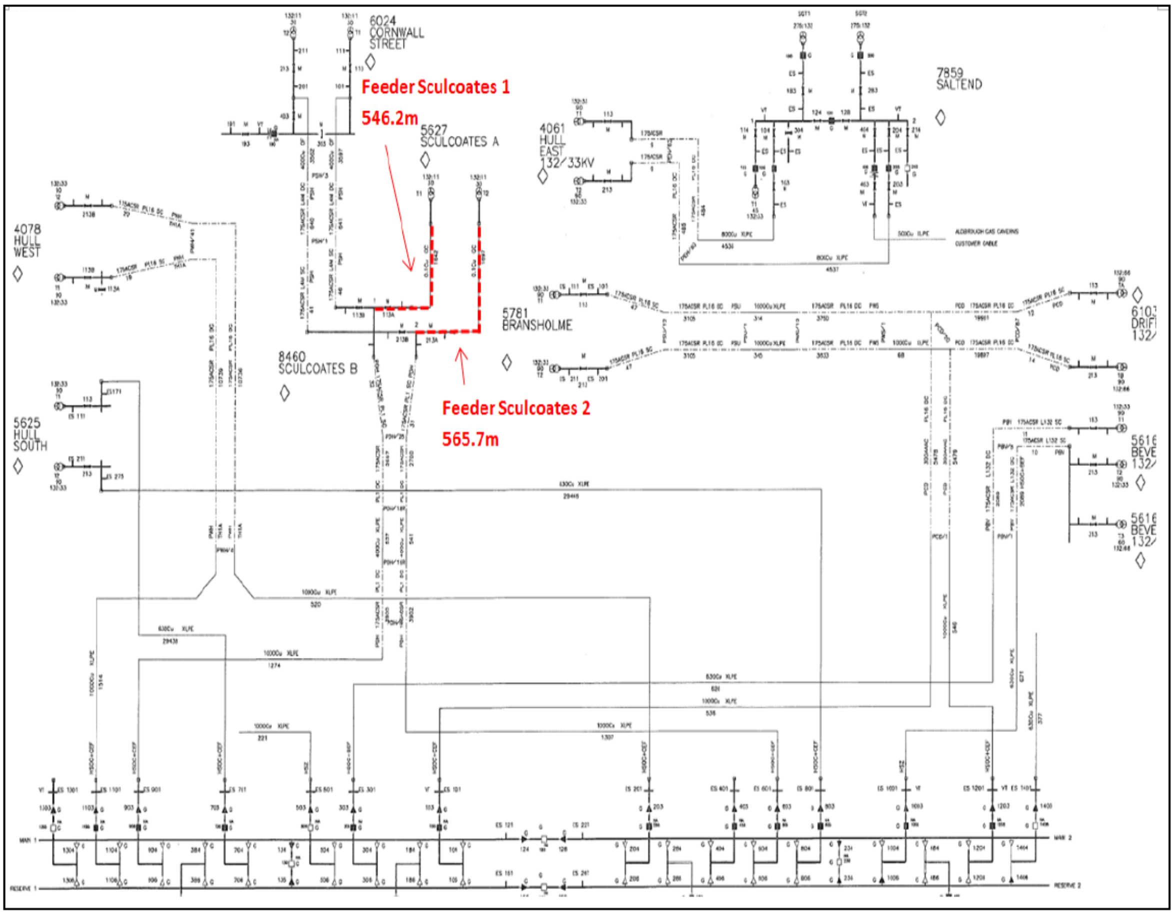


Figure A3.1: System diagram showing the gas-filled cables to be replaced

Figure A3.1 is an example of a simple 132kV network for losses CBA assessment, to replace the 0.1 Cu gas-filled cables on feeder Sculcoates 1 and 2 with 400 Cu XLPE 1c. The conductor CBA assessment template is used in this assessment. A load flow has been carried out and MD at feeder 1 and 2 is 12.28MVA and 13.52MVA respectively (transformer 1 and transformer 2 at Sculcoates A substation is split approximately 50%). LLF for both feeders is calculated by observing the half of load profile at Sculcoates A. The LLF is obtained as 0.37. Table A3.1 below are the losses calculations for feeder 1. Note that the parameters below follow the format in the CBA template.

The same exercise is carried out for feeder 2. The baseline cost is the cost incurred in retaining the gas-filled cables. This might include the cost to maintain the gas pressure and the associated environmental and customer interruption costs.

The CBA concluded that for a reduction of 4.4MWh of losses per year of the proposed option, with an increase in cost of £ 0.02M per kilometre, the NPV is negative for both feeders over the asset life of 45 years. In order for the investment to be worthwhile, the cost increase of the proposed conductors should not exceed about 1.9% of the baseline.

For guidance on distributed loads, see Appendix 4.

Parameters	Value	Formula	Calculation	Result
NETWORK DATA				
Maximum Demand, I (Amp per phase, not MVA)	53.71 A			
Load growth factor (optional)	0.50%			
Loss Load Factor, LLF	0.37			
Hours per year, H	8766			
Number of load points, n (input 1 for a point load)	1			
Length of conductor, L	0.566 km			
Feeder Loss Factor, FLF	1.000	$\frac{2n^2+3n+1}{6n^2}$		
BASELINE CONDUCTOR				
Cost per km, c_b	0.68 £M/km			
Resistance per km, r	0.339 Ω/km			
Resistance, R		$r \times L$	0.339×0.566	0.192 Ω
Phase (input 1 for single-phase, 2 for 2-phase or 3 for 3-phase conductor), Ph	3			
PROPOSED CONDUCTOR				
Cost per km, c_p	0.7 £M/km			
Resistance per km	0.062 Ω/km			
Resistance, R		$r \times L$	0.062×0.566	0.035 Ω
Phase, P (input 1 for single-phase, 2 for 2-phase or 3 for 3-phase conductor), Ph	3			
BASELINE losses per year, P_{LBy}		$Ph \times I^2 \times R \times LLF \times H \div 10^6$	$3 \times 53.71^2 \times 0.192 \times 0.37 \times 8766 \div 10^6$	5.38 MWh/yr
PROPOSED losses per year, P_{LPy}		$Ph \times I^2 \times R \times LLF \times H \div 10^6$	$3 \times 53.71^2 \times 0.035 \times 0.37 \times 8766 \div 10^6$	0.98 MWh/yr
BASELINE losses per year minus PROPOSED losses per year		$P_{LBy} - P_{LPy}$	$5.38 - 0.98$	4.40 MWh/yr
BASELINE cost per km minus PROPOSED cost per km, c_D		$c_b - c_p$	$0.68 - 0.70$	-0.02 £M/km
BASELINE cost minus PROPOSED cost		$c_D \times L$	$(-0.02) \times 0.566$	-0.01 £M
Year of Installation (RIIO ED1 ONLY))	2019			

Table A3.1: Losses Calculations for Feeder Sculcoates 1 of figure A3.1

A3.2) Example 2: Complex Network with Generation

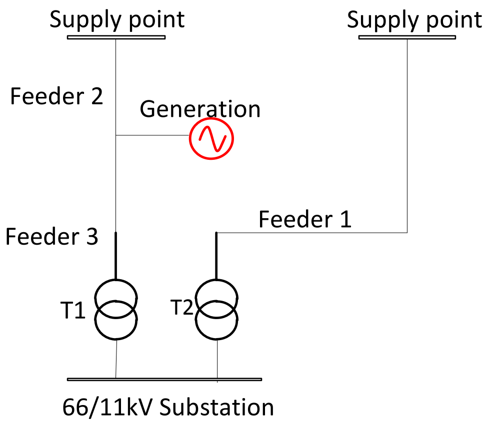


Figure A3.2: System diagram showing the oil-filled cables to be replaced

Figure A3.2 is an example of a complex 66kV network with generation for losses CBA assessment to replace the 0.3 Cu oil-filled cables with 300 Cu XLPE 1c for feeder 1, feeder 2 and feeder 3. These feeders need to be assessed individually. A loadflow study has been carried out. Feeder 1 shares approximately two-third of the substation load, with feeder 3 shares the remaining one-third of the load.

Calculating the LLF for feeder 1 and feeder 3 is straightforward. Only the substation loading is required:

$$LLF_{feeder\ 1} = LLF_{feeder\ 3} = 0.22 \tag{A3.1}$$

The LLF for feeder 2 is an aggregation of the substation (as seen by feeder 3) and the generation net profiles:

$$Profile_{aggregate} = \frac{1}{3} \times Profile_{substation} + Profile_{generation\ import} - Profile_{generation\ export} \tag{A3.2}$$

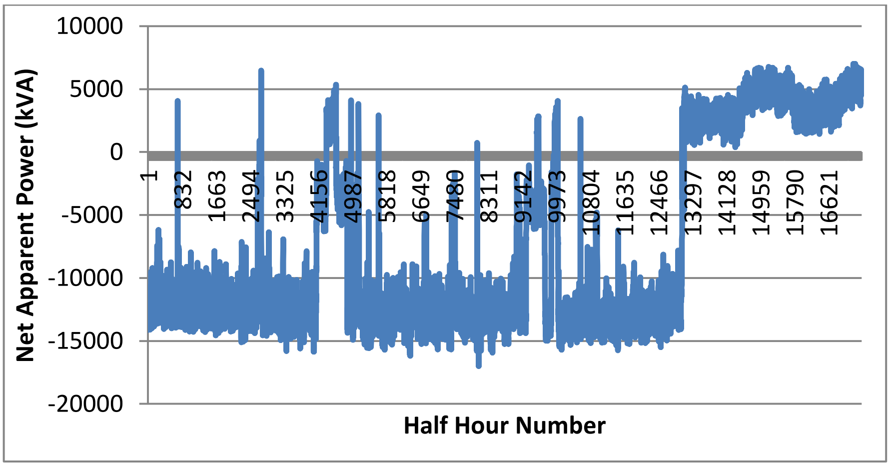


Figure A3.3: The aggregated profile to calculate the LLF for feeder 2

Note that the MD in figure A3.3 above is now 15,000 kVA, with reverse power-flow to the supply point in figure A3.2. Thus, the LLF for feeder 2 is different than feeder 1 and 3:

$$LLF_{feeder\ 2} = 0.49 \tag{A3.3}$$

The snapshot of the conductor CBA assessment, populated with data for feeder 1 of the circuit, is shown in figure A3.4:

Parameters	Values	Units
NETWORK DATA		
Maximum Demand (unit is in Amp not MVA)	27	A
Load growth factor (optional)	0.50%	
Loss Load Factor, LLF	0.22	
Hours per year	*8766*	*hours*
Number of load points, n (input 1 for a point load)	1	
Length of conductor	4.924	km
Feeder Loss Factor, FLF	*1.00*	
BASELINE CONDUCTOR		
Cost per km	0.4558	£M/km
Resistance per km	0.11	Ohm/km
Resistance	*0.56*	*Ohm*
Phase (input 1 for single-phase, 2 for 2-phase or 3 for 3-phase conductor)	3	
PROPOSED CONDUCTOR		
Cost per km	0.4560	£M/km
Resistance per km	0.08	Ohm/km
Resistance	*0.38*	*Ohm*
Phase (input 1 for single-phase, 2 for 2-phase or 3 for 3-phase conductor)	3	
BASELINE losses per year	*2.32*	*MWh/yr*
PROPOSED losses per year	*1.59*	*MWh/yr*
BASELINE losses per year minus PROPOSED losses per year	***0.73***	***MWh/yr***
BASELINE cost per km minus PROPOSED cost per km	***-0.0002***	***£M/km***
BASELINE cost minus PROPOSED cost	***-0.0010***	***£M***
Year of Installation (RIIO ED1 ONLY)	2019	

Figure A3.4: Populated conductor CBA assessment template for feeder 1

The same template is populated for feeder 2 and 3. While feeder 2 and 3 give negative NPVs respectively, the result for feeder 1 shows that the slight increase in investment breaks even in year 2042. Therefore this is a worthwhile investment over an asset life of 45 years.

Appendix 4 – Feeder Loss Factor (FLF) for Distributed Loads

Most network feeders at low and high voltage feed distributed loads along the feeder. The assumption that all load on the feeder is at the end is therefore not representative of actual loading conditions and can exaggerate the I^2R loss figures. This example considers an LV feeder where the load is equally split into three along the feeder.

The length of the feeder is 0.5km, supplying three distributed loads with a total of 300A per phase: -
I_s = Phase current increment per section = (300÷3) = 100A
R_{1000} = Phase Resistance per km = 0.205Ω/km
R = Phase Resistance of cable = 0.2050×0.5 = 0.1025Ω
R_s = Resistance of section = 0.1025÷3 = 0.0341Ω

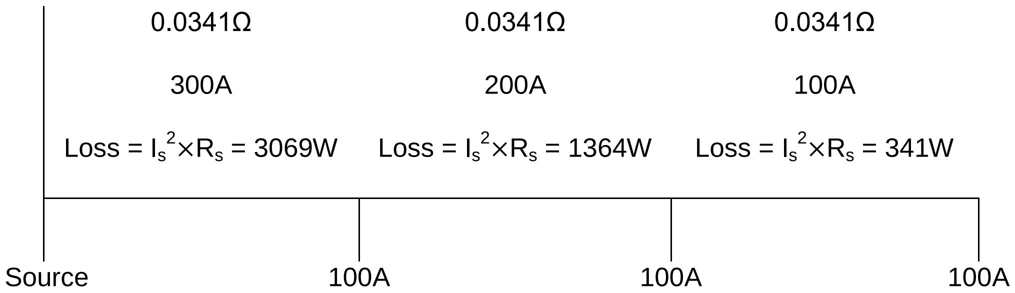


Figure A4.1: Distributed LV feeder where the load is equally split into three

$$\text{Total Loss} = 3\times (3069 + 1364 + 341) = \mathbf{14.3kW} \qquad \text{(A4.1)}$$

The above method becomes computationally inefficient when the number of feeder section is increased to represent typical networks with scores of load points connected. The square pyramidal number method can greatly increase the efficiency of the calculation by looking at the effect of incremental $I^2 \times R$ (shown as $I_s^2 \times R_s$). Consider the same scenario above but using three generic sections: -

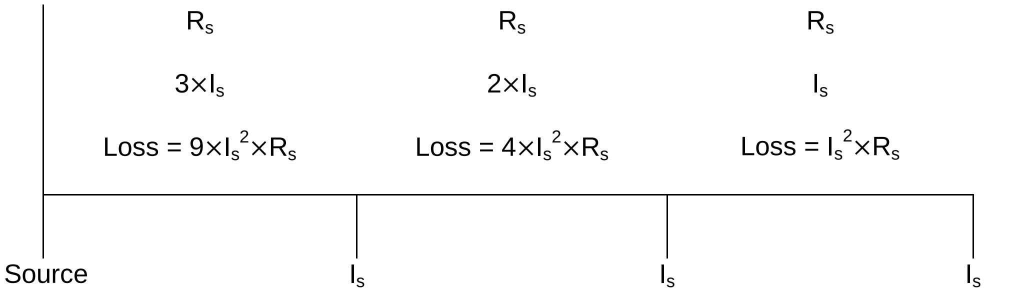


Figure A4.2: Distributed LV feeder with three generic sections

$$\text{Total Loss} = 9\times I_s^2 \times R_s + 4\times I_s^2 \times R_s + I_s^2 \times R_s = \mathbf{14\times I_s^2 \times R_s} \qquad \text{(A4.2)}$$

$$\text{Total Loss} = 3\times (14\times 100^2 \times 0.0341) = \mathbf{14.3kW} \qquad \text{(A4.3)}$$

For n load points, the number of sections in the feeder gives the sums of $I_s^2R_s$ which follows the square pyramidal pattern as shown in table A4.1:

Load points (n)	Quantity of $I_s^2R_s$ (Pn)
1	1
2	5
3	14
4	30
5	55
6	91
7	140
8	204
…	…
n	$\frac{2n^3+3n^2+n}{6}$

Table A4.1: the formation of the square pyramidal load pattern.

Consider a feeder having a point load, with load I and resistance R.

If the feeder is now segmented into n section due to the distributed load:

$$I_s = \frac{I}{n} \quad \text{(A4.1)}$$

$$R_s = \frac{R}{n} \quad \text{(A4.2)}$$

From table A4.1, the sums of $I_s^2R_s$ (Pn):

$$= \frac{2n^3+3n^2+n}{6} \times I_s^2 \times R_s \quad \text{(A4.3)}$$

Substituting (A4.1) and (A4.2) into (A4.3):

Thus the variable loss for the feeder per phase:

$$= \frac{2n^2+3n+1}{6n^2} \times I^2 \times R$$

$$= \boldsymbol{FLF} \times I^2 \times R \quad \text{(A4.4)}$$

Where FLF shall be called the Feeder Loss Factor, which is a function of the number of load point n. This factor can be used to multiply with the 'losses if it was a point load', to obtain the losses as a result of the distributed demand.

n can be solved as follows, noting that:

$$\lim_{n\to\infty} \frac{2n^2+3n+1}{6n^2} = \frac{1}{3} \quad \text{(A4.5)}$$

Figure A4.3 below shows a graph of FLF as a function of load point, for 100 load points:

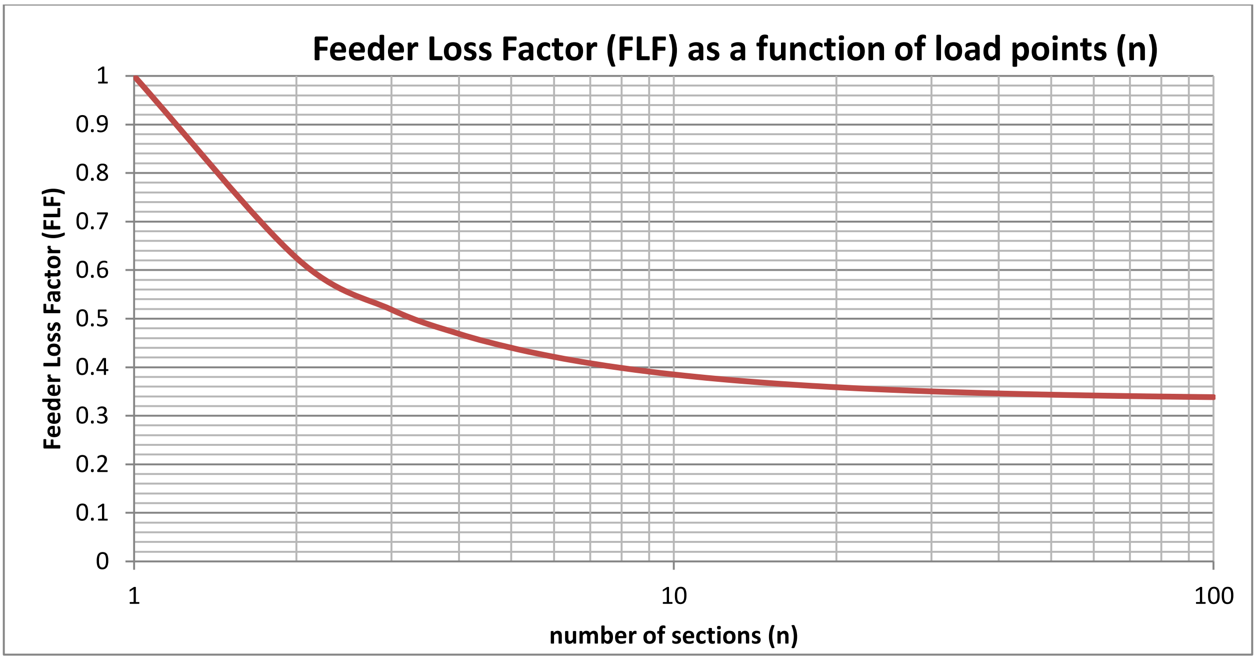


Figure A4.3: Graph of Feeder Loss Factor for 100 load points. X-axis is on a logarithmic scale, while y-axis is on a linear scale

As explained in the flowchart in figure A1.1, 10 load points is suggested for an urban HV feeder. This gives an FLF value of 0.39. For rural LV and HV feeder, 50 load points is suggested, which gives an FLF value of 0.34. This graph is also included in the CBA template for conductor.

Appendix 5 – Transformer Losses Examples

The following table is a snapshot of the transformer CBA template used to compare two transformers: -

Parameters	Values	Units
NETWORK DATA		
Load growth factor (Optional)	0.00%	
Loss Load Factor, LLF	0.25	
Site demand	0.90	MVA
Hours per year	*8766*	*hours*
BASELINE		
Quantity of transformers	1	
Individual transformer rating	1	MVA
Individual transformer utilisation	*0.90*	
Individual copper losses (variable Losses)	10	kW
Individual iron losses (fixed losses)	1	kW
Cost of individual transformer	£ 10,000.00	
Total cost of transformers	*£ 10,000.00*	
Total BASELINE copper losses per year	*17.751*	*MWh/yr*
Total BASELINE iron losses per year	*8.77*	*MWh/yr*
Total BASELINE losses per year	*26.52*	*MWh/yr*
PROPOSED		
Quantity of transformers	1	
Individual transformer rating	1	MVA
Individual transformer utilisation	*0.90*	
Individual copper Losses (variable losses)	9	kW
Individual iron losses (fixed losses)	0.75	kW
Cost of individual transformer	£ 15,000.00	
Total cost of transformers	*£ 15,000.00*	
Total PROPOSED copper losses per year	*15.98*	*MWh/yr*
Total PROPOSED iron losses per year	*6.6*	*MWh/yr*
Total PROPOSED losses per year	*22.6*	*MWh/yr*
Total BASELINE copper losses minus total PROPOSED copper losses, per ye	***1.78***	***MWh/yr***
Total BASELINE iron losses minus total PROPOSED iron losses, per year	***2.2***	***MWh/yr***
Total BASELINE losses minus total PROPOSED losses	***4.0***	***MWh/yr***
BASELINE cost minus PROPOSED cost	***-£ 0.005***	***£M***
Year of Installation (RIIO ED1 ONLY)	2019	

Figure A5.1: Populated transformer CBA template to compare two transformers

The result shows that the increased investment breaks even in year 2044. Therefore this is a worthwhile investment over an asset life of 45 years.

If a load growth is required, the copper losses can be multiplied by a growth rate to give a loss profile over the asset life.

Appendix 6 – Capitalised Losses for Transformer Procurement

This appendix shows how the capitalised cost per kW for iron and copper losses for a range of transformers on the system was calculated.

The iron loss value is constant across the transformer population as it is assumed that all transformers will be energised all year and any outages will be negligible. The copper loss value, however, varies, depending on the load profiles for the different classes of transformers. The capitalised cost of losses for system transformers should be calculated on a project basis using the Northern Powergrid capitalised loss transformers template. To estimate the LLF for distribution transformers, the CLNR data has been used to show the relationship between LLF and domestic customer numbers, as depicted in figure A6.1 below (note that the x-axis is a logarithmic scale and the y-axis is a linear scale):

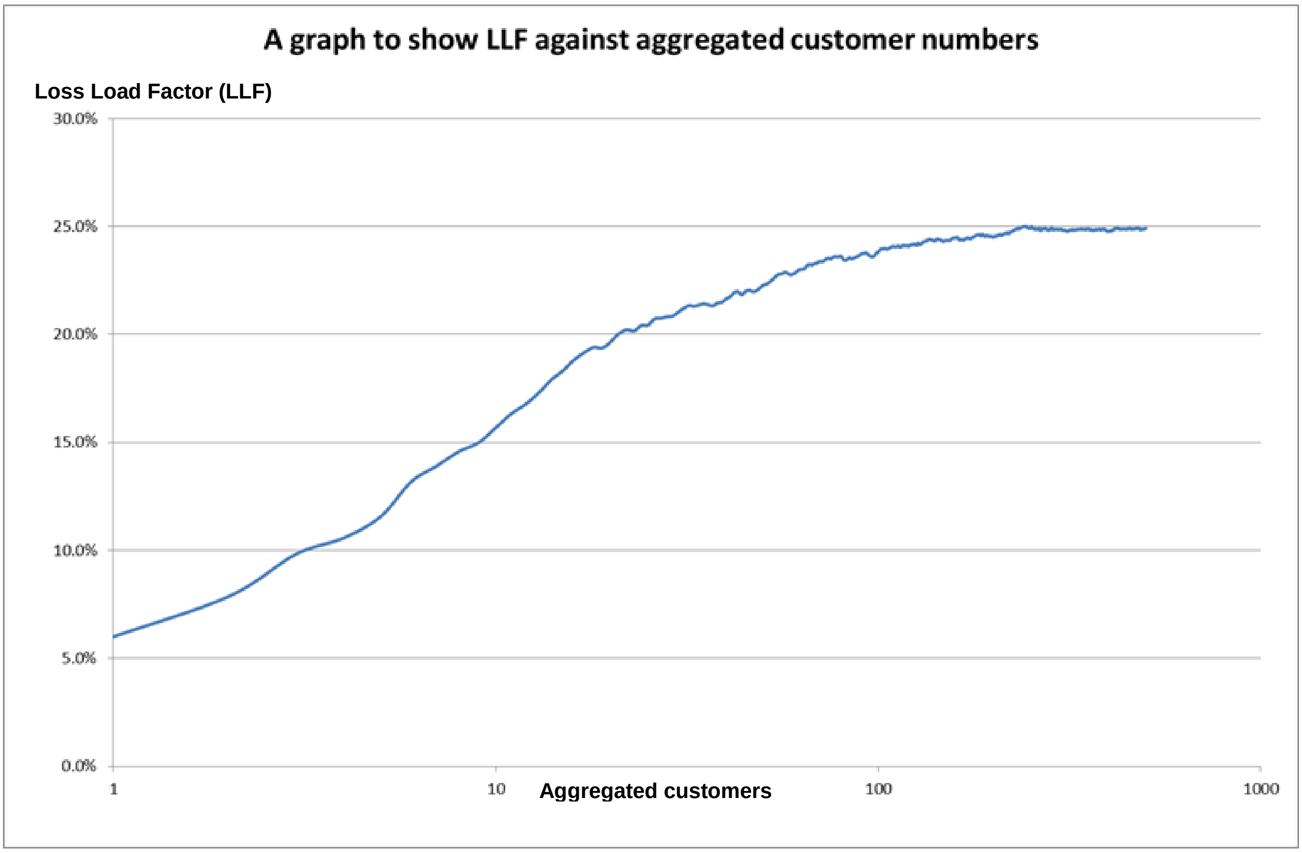


Figure A6.1: A graph showing the LLF for aggregated domestic customer numbers

The weighted average customer numbers on pole mounted transformers in Northern Powergrid Yorkshire is approximately 13 customers and on ground mounted transformers approximately 140 customers. For consistencies and using the above graph, the LLF of 0.15 can be used for pole mounted transformers and 0.225 for ground mounted transformers. Given these values and 0.5% load growth, the following values were obtained from the Northern Powergrid template on valuing the capitalised costs of losses for transformer procurement:

Transformer	Iron loss value	Copper loss value
Pole mounted distribution	£12,217/kW	£737/kW
Ground mounted distribution	£12,217/kW	£1,471/kW
System transformer	£12,217/kW	To be calculated on a project basis using template

Appendix 7 – Design Solution Examples

A7.1) Network Reconfiguration

A design is carried out for a major network reconfiguration to install two new circuits out of a primary substation. The aim is to split two heavily-loaded circuits as well as to pick-up adjacent primary network for P2 compliance. The total cost of the scheme is £870,000, including the cost of extending the primary busbar to add two new circuit breakers. A load flow has been carried out on the existing primary network, with the following result:

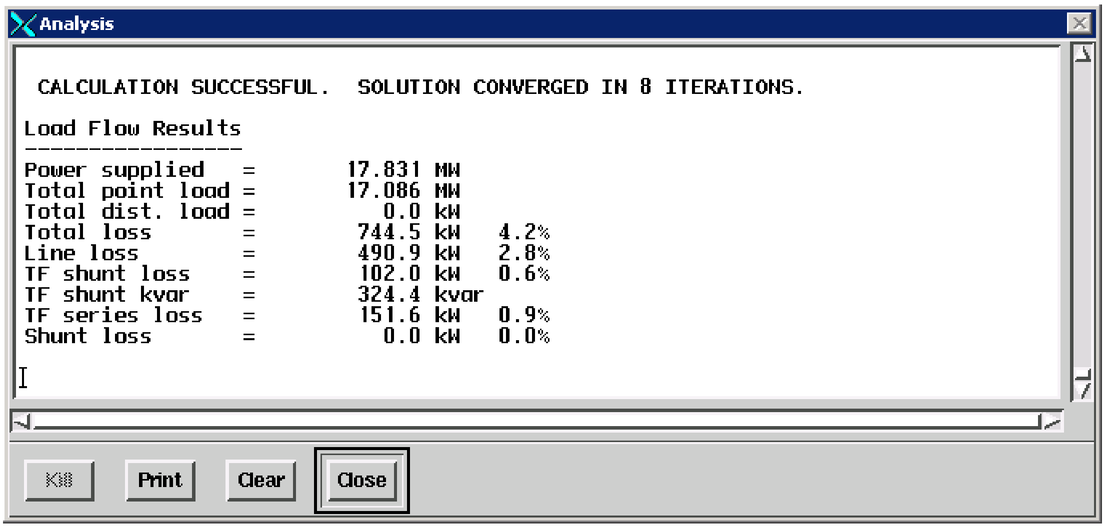


Figure A7.1: Load flow results of the existing system

The load flow results for the proposed design is as below:

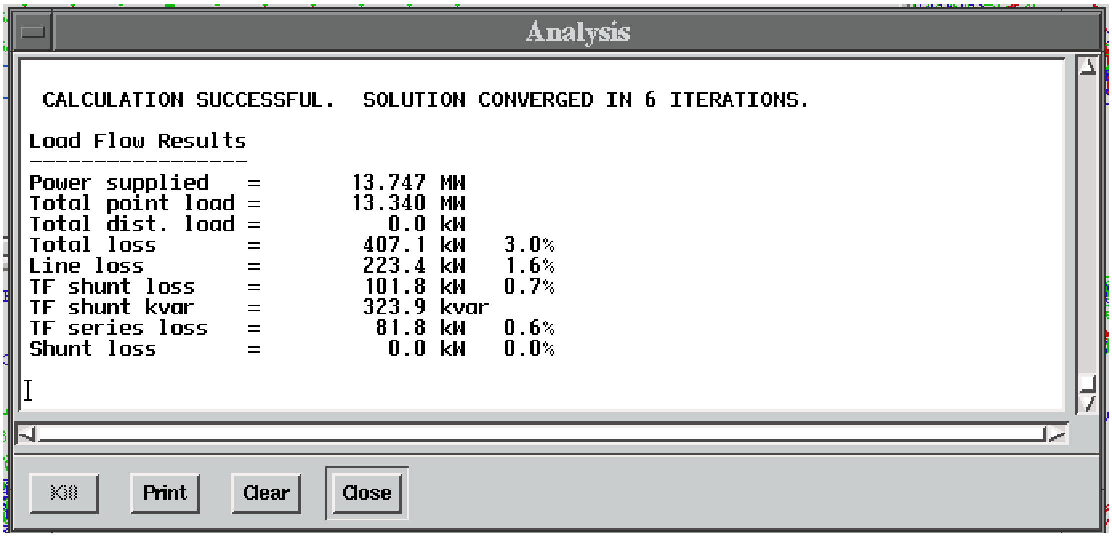


Figure A7:2: Load flow result of the proposed design

LLF of the existing primary network = 0.26.

The following table is a snapshot of the design solution CBA template to assess the losses benefit of the network reconfiguration over the capital investment.

Parameters	Values	Units
NETWORK DATA		
Load growth factor (Optional)	0.50%	
Loss Load Factor, LLF *(see note below)*	0.26	
Hours per year	*8766*	*hours*
BASELINE OPTION		
Variable losses	642.5	kW
Fixed losses	102.0	kW
Cost of BASELINE option	£ -	
Total BASELINE variable losses per year	*1464.4*	*MWh/yr*
Total BASELINE fixed losses per year	*894.1*	*MWh/yr*
Total BASELINE losses per year	*2358.5*	*MWh/yr*
PROPOSED OPTION		
Variable losses	305.3	kW
Fixed losses	101.8	kW
Cost of PROPOSED option	£ 870,000.00	
Total PROPOSED variable losses per year	*695.83*	*MWh/yr*
Total PROPOSED fixed losses per year	*892.38*	*MWh/yr*
Total PROPOSED losses per year	*1588.21*	*MWh/yr*
Total BASELINE variable losses minus total PROPOSED variable losses, per ye	***768.53***	***MWh/yr***
Total BASELINE fixed losses minus total PROPOSED fixed losses, per year	***1.75***	***MWh/yr***
Total BASELINE losses minus total PROPOSED losses	***770.29***	***MWh/yr***
BASELINE cost minus PROPOSED cost	***-£ 0.87***	***£M***
Year of Installation (RIIO ED1 ONLY)	2019	

Figure A7.3: Populated design solution CBA template to assess the losses benefit of a network reconfiguration

The CBA shows that the investment to reconfigure the 11kV network breaks even in year 2036, besides improving system interconnection, reliability, performance and achieving P2 compliance. Therefore this is a worthwhile investment over the life expectancy of the design of 45 years.

A7.2) Aggregated generation LLF curve

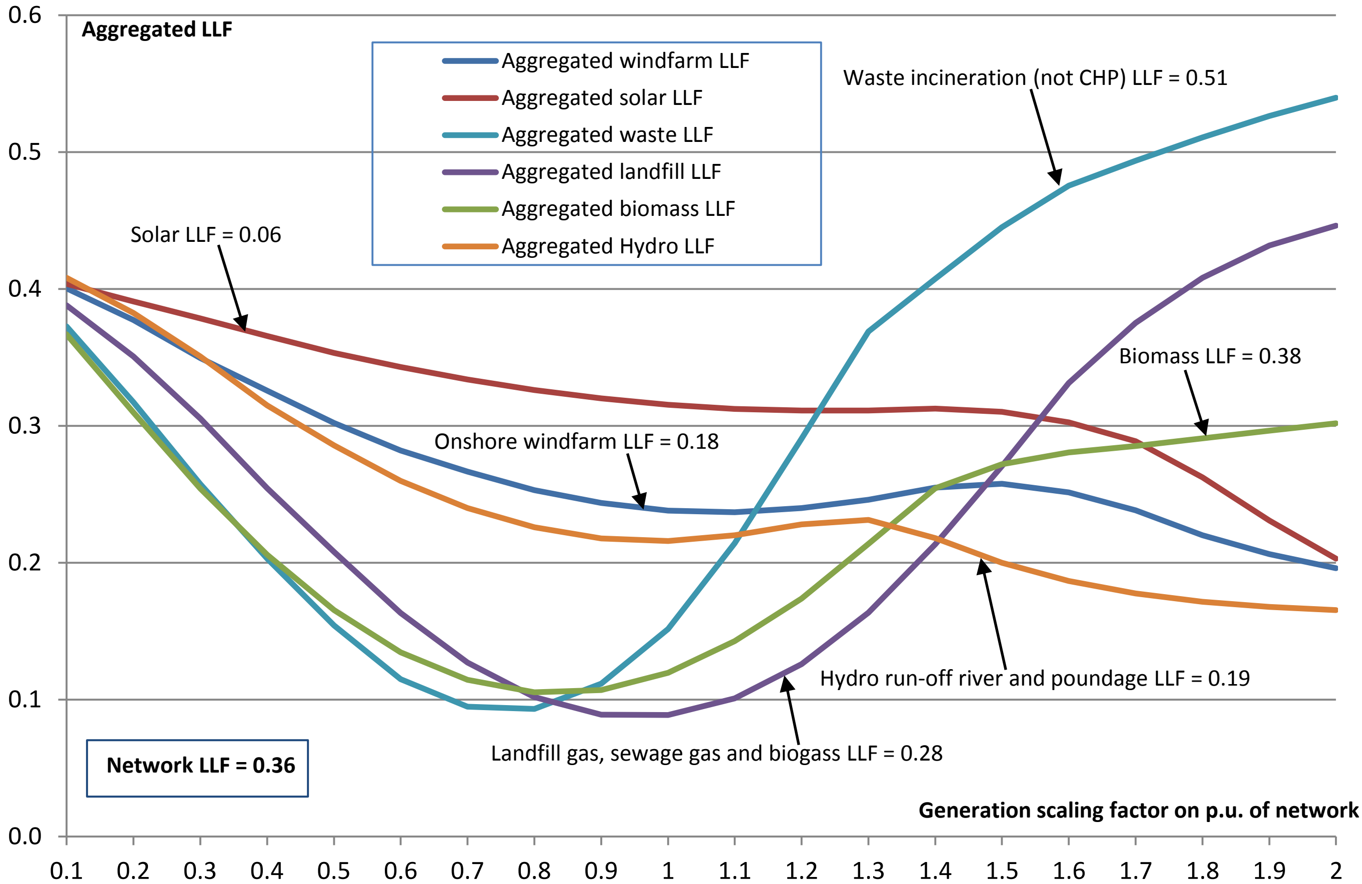


Figure A7.4: Aggregated generation LLF curve of typical generation types

The aggregated generation LLF curve above shows the impact of different generator size on a typical network (with LLF of 0.36) for six different types of generation, in terms of the LLF. The x-axis of the graph is the generation scale factor on the per-unitised network, while the y-axis is the LLF of the aggregated profile of the generation and the network. It can be seen that for a generation with firm and steady output, reflected by a high LLF value (i.e. waste), the impact on losses is greater than the generation with low LLF (i.e. solar). It can also be seen that for waste, biomass and landfill, the losses are lowest when they are about the same size with the network, i.e. when the generation export matches the network demand.

This curve can also guide design engineers when optioneering different point of connections where the new generation materially change the existing network profiles, by providing the aggregated LLF value for CBA to include the cost or benefit of losses into the overall cost estimate.

For example:

- A new waste generation of 5MVA export and 1MVA import will be connected on a primary network of 10MVA maximum demand. The scaling factor is 0.45 (which is 5MVA ÷ 11MVA).
- Looking at the aggregated generation LLF curve for waste incineration (not CHP), the aggregated profile will have LLF of 0.16. This LLF value can then be used to calculate the impact of losses using the CBA design solution template, either cost or benefit, depending on the loadflow result before and after connecting the generator.

A7.3) New Connection (generation)

Max export	PoC volt[20]	Connection Type	NC cost estimate[21]	Cont cost estimate[22]	Total cost estimate	Losses increase (kW)[23]	Cost of losses[24]
63MW	132kV	Install a new 132/66kV transformer (GT4) at supply point (SP) and install 6km of single 66kV cable to terminate into 66kV metering s/s at the customer's site	£3.32m	£6.71m	**£10m**	Variable=564 Fixed=100	£2.43m
60MW	132kV	Install a new 132/33kV GT4 at SP and install 6km of 2x33kV cables to the customer's site	£3.38m	£6.10m	**£9.47m**	Variable=803 Fixed=142	£3.46m
63MW	132kV	Loop into the 132kV overhead line circuit and install approximately 2x2km of 132kV cable to the customer's site and install 132/33kV transformer	£2.77m	£7.76m	**£10.50m**	Variable=535.6 Fixed=95	£2.31m
63MW	132kV	Tee-off the existing GT2 132kV busbar at SP and install 6km of 132kV cable connecting the a new 132/33kV transformer at the customer's site	£1.50m	£8.79m	**£10.3m**	Variable=565 Fixed=99	£2.43m

Figure A7.5: Optioneering for 63MW biomass connection, embedding the cost of losses

Figure above shows how the cost of losses is included in the optioneering process of connecting a 63MVA biomass.

- Grid Supply Point MD = 307.46 MVA
- Generation scaling factor = 0.20
- From the aggregated generation LLF curve in figure A7.4 for biomass, the aggregated LLF = 0.32

The cost of losses is obtained by applying the CBA template for design solution using the data above and the losses increase values obtained from DINIS. This example illustrates how a design process could include the valuation of losses over the anticipated lifetime of the design solution as an input to the design optioneering.

20 Point of connection voltage

21 Non-contestable cost estimate

22 Contestable cost estimate

23 The increase in losses due to the generation connection, obtained from DINIS model

24 Cost of losses over the expected lifetime of the generation design solution of 20 years, with a load growth of 0.5%