MERLIN

Modelling the Economic Reactions Linking Individual Networks

Milestone 6

Fort William Modelling Evaluation

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Scottish & Southern Electricity Networks

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1 Introduction

1.1 Background

The MERLIN project is working towards improving our understanding on how Distribution Network Operators (DNOs) or Distribution System Operators (DSOs) can effectively manage flexible services (for their own use or as neutral facilitators) such as those provided by generators, energy storage units and demand side response, among others. The goal is to improve our understanding on the economic impact these flexible services could have in a number of possible future world scenarios. MERLIN is also exploring the impacts of managing constraints through traditional reinforcement and alternative DNO controlled methods, which can be used to evaluate the cost-effectiveness of flexible services. Modelling allows us to understand possible positive and negative financial impacts of flexible services in a safe and risk free environment, with relevant learning passed to sister innovation projects TRANSITION and Project LEO. This can help us make better and more informed decisions in order to reduce customer costs and support the drive to net zero.

1.2 Aim

The aim of this report is to provide an overview of the process used to create network models within the Grid OS Integrated Distribution Planning (IDP) tool and to evaluate the performance of the tool i.e. pros and cons and how it could be improved. The report also provides an overview of the modelling results and gives insight into the implications of these results.

2 Grid OS IDP Evaluation

2.1 Network Models Software Platforms

The methodology used for completing the modelling of the Fort William (FW) region previously developed in the GridOS IDP tool is mainly deployed on three software packages. In particular, Microsoft Excel, Python and the Grid OS platform. Figure 2-1 provides the different platforms used for the deployment of the FW model.

- Microsoft Excel is used for displaying, managing, organising and storing the data. Namely, Excel is responsible for the complete stream of input and output data used and produced by the FW methodology to finalise the network models and perform the power systems evaluation. The excel outputs are used to verify that the outputs from Grid OS IDP are accurate i.e. Powerflow outputs are as expected and estimated costs are as expected. This is an essential step to ensure that Grid OS IDP is producing accurate outputs.

- Python is used to read, process, calculate and manage the input data from Excel to conduct the power systems studies for the FW region. Also, Python is used for an extra two main processes. The first one is an intermediary tool that helps to communicate between Excel and GridOS IDP tool. In the second process, Python provides a set of commands to GridOS IDP to directly modify the network model and parameters.

- The GridOS IDP tool is utilised to perform the power systems analysis. It mainly assesses the network violations (i.e. thermal and voltage constraints) caused within the network due to the implementation of the load and generation forecasts throughout the ten-year period. Once the analysis is finished, the GridOS IDP returns to Excel to produce the required output data.

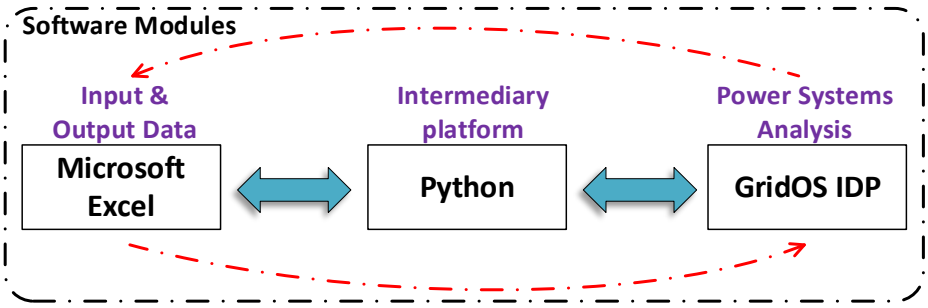


Figure 2-1: Software packages modules used for the FW region model

2.2 Network Models Methodology

The flow chart of the methodology employed for conducting the power systems studies of the FW region is depicted in Figure 2-2. The methodology is divided into three main sections. The first section aims to illustrate the key input data required for completing the FW model. The second section includes the modelling calculation procedures needed for the power systems evaluation. The third section involves the set of output data produced to determine the grid performance regarding network violation when accommodating load and generation forecasts. The three sections are described below.

A) Input data

The input data includes the information regarding the embedded generation and required demand. The data is utilised to conduct the power systems analysis to find the most suitable solution for removing the network constraints, using traditional reinforcements (i.e. new circuits, transformers, bigger cables, etc.) and flexible services such as storage systems, demand response and distributed energy resource among others.

The required input data is mainly divided into two streams of data, namely, generation data and demand data. Their description is as follows.

1. Generation Data: A minimum set of data is required to complete the FW region model during the methodology implementation. In particular, the generation data includes the hydropower plants, the rooftop solar generation (PV) and the representative generation illustrating the equivalent network deployed at 33kV.

2. Demand Data: A complementary input data is additionally required to perform the power systems analysis. Namely, heat pump (HP) along with historical PI loading data, electric vehicles (EV) at a domestic and non-domestic level, and the representative loads from the 33kV equivalent network.

Once the completed stream of input data is obtained, the generation and demand forecasts are generated by capitalising on data from a second project led by Regen (this work was completed by Opus One Solutions).

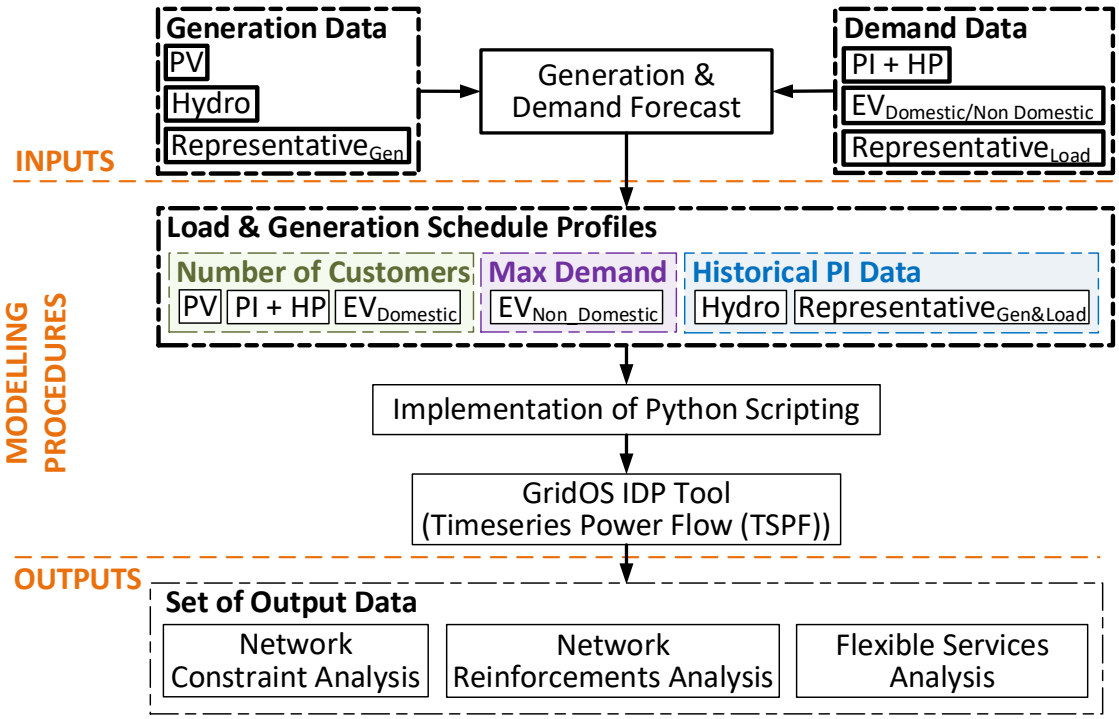


Figure 2-2: Methodology flow chart used for the FW region studies

B) Modelling Calculation Procedures

It involves the process of handling the generation and demand forecast data to create the load and generation schedules profiles. This is an essential process performed through Python scripting, required by the Grid OS tool to conduct the time series power flow (TSPF) in the FW region.

The modelling calculation procedures is also split into three main parts. Specifically, the first part involves the production of the load and generation schedule profiles. The second part uses Python scripting to implement these profiles and modifying the network model. The last part utilises the GridOS IDP tool to execute the TSPF and the power system analysis. The three parts are described as follow.

1. Load & Generation Schedule Profiles: Three main methods are employed to determine the schedules profiles of both generation and demand. Particularly, the number of customers, maximum demand, and historical PI data (Figure 2-2).

   - Number of Customers: Each feeder's total demand or generation is spread to the individual nodes considering the number of customers connected. For example, a total feeder demand or generation of 100 kW containing four different nodes with 25 customers connected to each one will result in every node having a total demand or generation of 25 kW. The approach applies to PV, PI + HP and domestic EV.

   - Maximum Demand: The total demand of each feeder is distributed as a proportion of the maximum demand among the nodes with maximum demand customers only. For example, a total feeder demand of 15 kW containing two nodes defined as Node 1 and Node 2, with a maximum demand of 50 kW and 100 kW each, respectively, will result in Node 1 having a total demand of 5 kW, and Node 2 of 10 kW. The method applies to non-domestic EV only.

   - Historical PI Data: Based on historical data regarding the hydro generation and power flows along the overhead lines and transformers, a baseline case is created to derive a specific network section's demand and generation profiles. The aim is to reduce the network and build an equivalent network model to facilitate the power systems analysis. For this purpose, a terminal point (i.e. bus) is selected. The network elements connected downstream are represented as a single load or source of generation depending on the sign of the power flows. Thus, it is assumed that positive flows represent demand at the terminal point, whereas the negative flows correspond to generation. An example is shown in Figure 2-3. The method is employed for hydro and the representative load and generation schedule profiles.

2. Implementation of Python Scripting: Python is mainly used as the intermediary tool to manage and process the input data from Microsoft Excel to the GridOS IDP tool. Also, it provides direct commands to the GridOS for modifying the network model. Thus, Python is used for reading and processing the generation demand forecasts in Excel format coming from the input data. Then, based on the type of demand and generation embedded within the network model (i.e. EV, PV, Hydro, etc.), it proceeds to build the schedule profiles from both load and generation. To this end, the three methods discussed above are employed.

Once the load and generation schedule profiles are completed, Python creates two potential forecast scenarios within the GridOS IDP tool to allocate these profiles. Particularly, Community Renewables (CR) and Consumer Evolution (CE) captured from the Regen report.

Also, Python scripting is employed for conducting modification within the network model developed by the GridOS tool. For instance, the inclusion of the representative load and generation at 33 KV, and the insertion of the hydro generation at 11KV. Finally, Python is used for adjusting the power rated of the EVs, hydro, and PVs element from the network in the FW region.

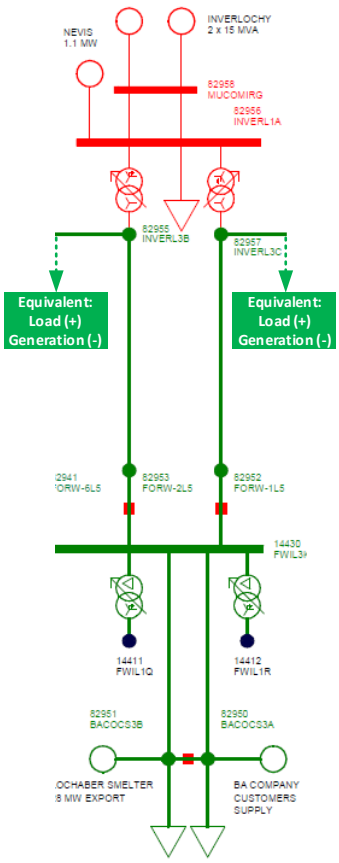


Figure 2-3: Example of an Equivalent Model Representation from the FW region

3. GridOS IDP Tool: It is an integrated distribution planning tool that uses a common information model (CIM) for creating grid models to perform power systems analysis. To this end, GridOS needs load and generation forecast for conducting timeseries power flow. Thus, the set of data created by the Python scripting is used as input data by the IDP tool to proceed with the power system evaluation. Specifically, it intends to identify the network violations that occurred within the network model originated by the load and generation forecasts. After finding the constraint within the model, conventional reinforcements and flexible sources are modelled, simulated, and compared to determine a suitable solution for removing the grid violations.

C) Output Data

The simulation output is the final stage of the methodology illustrated in Figure 2-2. Thus, the set of output data describing the performance of the network model representing the FW region are produced. Particularly the network constraint, reinforcements, and flexible services analysis. The purpose of the analysis is to enhance the existing mechanisms and practices for addressing the network violation occurrences within the network and provide new insights on the contribution of these approaches to the grid's performance.

2.3 Quality Checking Network Models

A quality control process is conducted to ensure the quality of the network models deployed by the FW region. The aim is to assess the accuracy of the data used for building the models. The followed procedure is depicted in Figure 2-4.

The quality control process starts with the network topology checking step. The objective is to compare the Grid OS IDP model connectivity against the Power On single line diagram (SLD). The process also includes reviewing the conductors employed for producing the models and the completed network connectivity through the switches and circuit breakers elements.

Subsequently, a set of network component variables are additionally reviewed. This step includes evaluating the lines, breaker/switches, transformers, shunt, and synchronous machines parameters. Figure 2-4 shows the completed set of variables assessed for each network element. Then, the load and generation schedule profiles previously created (further details Section 2.2) are utilised for conducting a power flow study. The primary purpose is to determine the voltage and current convergence within the model. If not obtaining voltage/current convergency, a re-evaluation of the network variables is carried out to find a potential inaccuracy in the network settings. Conversely, the network model is ready to use for power system studies.

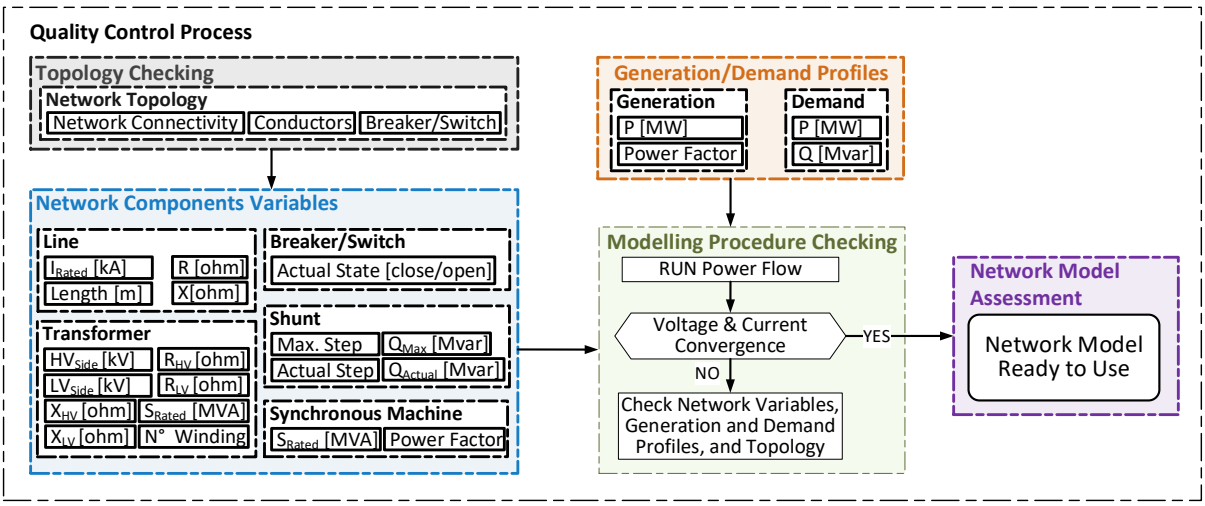


Figure 2-4: Quality control process for FW models

2.4 Evaluation of the Grid OS IDP Tool

GridOS IDP is an integrated distribution planning platform designed to support the advancement of the electricity grid. It is a versatile tool that allows comparing the analysis of the results to choose the most cost-effective solutions based on the grid's future needs. It is a cloud-based platform, so no installation is required making it quite simple to operate. Also, it utilises CIM for its data schema, which facilitates the standard-based network modelling implementation.

Overall, the GridOS is a handy and straightforward tool for performing power system studies. Nevertheless, based on the experience of utilising this tool developed during the Merlin project, a list of potential enhancements and recommendations is suggested. Their description is as follows.

- Manual: The GridOS manual does not provide a sufficient amount of information for solving a problem. In some cases, the piece of information is minimal or not included e.g. API documentation.

- Allocation of load profiles: Currently, at the feeder level, the IDP platform supports the distribution of load schedules based on the connected capacity of each node derived from the primary substation transformer capacity only. An additional feature should be added to distribute the load schedules based on the number of customers connected (this is the method used by SSEN planners). At the moment, this can be done externally through a Python script only.

- Line Rating: The tool does not support multiple line rating implementations such as seasonal line rating (e.g. winter, summer, and spring ratings), so a manual modification of the line ampacity must be conducted. As a result, it limits the annual time-series power flow application.

- Graphical Interface: The network model representation in the GridOS platform tend to be confusing since individual network elements are not easy to identify. For example, in some cases, the distribution lines, synchronous machines, nodes and switches are entirely overlapped, resulting in significantly challenging identification of the individual network components, and therefore, potential issues created by them.

- Power Flow Results: The acquisition of the results is limited. Average values are provided only. The lack of flexibility for obtaining the results limits the tool's capability and, therefore, the power system analysis. Ideally, the tool should provide the power flow results at any resolution in time (e.g. hourly, per minutes, etc.) and per any desired network element (e.g. lines, bus, PV, etc.).

- Network Element Names: The names used to identify the network elements within API documentation from the GridOS tool lack consistency, making it significantly challenging to distinguish them for modification purposes. The same label is described with capital letters, underscore symbol, and lower letters. Consequently, the manipulations of these network elements through API becomes highly challenging. A list of some examples is described below.

    - electric_vehicle_charging_station_info

- ElectricVehicleChargingStationInfo
- ElectricVehicleChargingStation
- ev_station
- photo_voltaic_unit_info
- PhotoVoltaicUnitInfo
- pv
- Inverter
- power_electronics_units
- inverter_info
- InverterInfo
- inverterpv
- EnergyConsumer
- energy_consumer
- Feeder
- feeder
- synchronous_machine
- SynchronousMachine

3 Model Results

3.1 Introduction

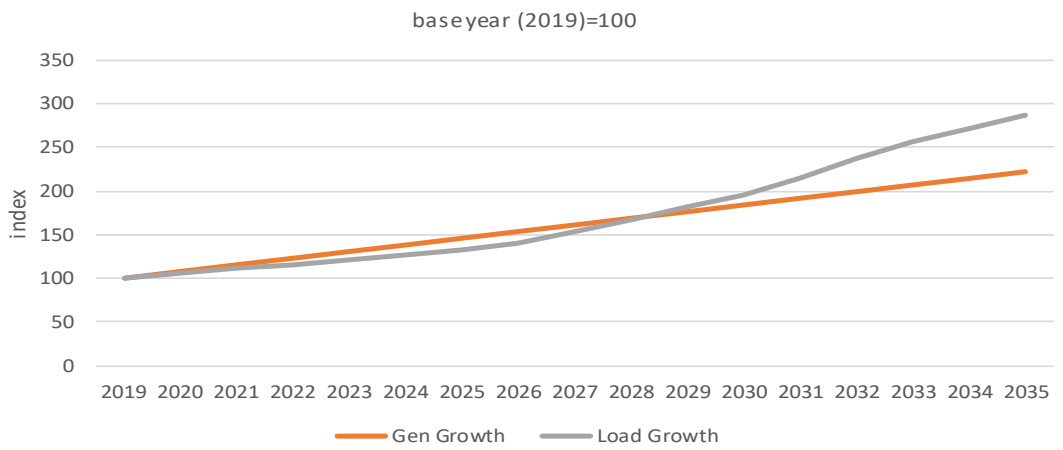
The aim of this study is to quantify and compare different intervention models to deal with thermal constraints in Scottish and Southern Electricity Network's (SSEN) Fort William region, in the context of Project Merlin.

A cost benefit analysis (CBA) is performed for this purpose based on the Common Evaluation Methodology (CEM) CBA tool developed by Baringa for the Energy Networks Association – ENA (Baringa, 2020). The benefits are represented by the net present value (NPV) difference of the baseline approach (i.e. traditional solution) and other alternative options such as the procurement of flexibility services. The traditional solution in this study suggests the upgrade of two conductors, at 11kV and 33kV by 2030 and 2032, respectively.

Information about flexibility requirements was provided by SSEN for the period 2026-2035. The scenario used for forecasting generation and load growth was the National Grid ESO Future Energy Scenarios (FES): Community Renewables (NGESO, 2019). This scenario proposes a more decentralised energy landscape to meet the decarbonisation targets, with significant participation of small scale, local and domestic activity. This is the scenario with the largest deployment of distributed generation and connected demand (e.g. heat pumps, EVs), Regen (2019).

Figure 1 illustrates the forecast generation and load growth in Inverlochy primary (Fort William region), which is the region evaluated in this report.

Figure 5: Forecast generation and load growth in Inverlochy primary region (CR scenario)



Source: SSEN

The report is organised as follows. Section two explains the methodology for estimating the flexibility requirements and the size of this on two constrained lines (11kV and 33kV). Section three introduces the cost benefit analysis methodology to value flexibility by comparing the business-as-usual (BAU) solutions with two other options where flexibility is contracted from DER. Section four explains the scenarios evaluated (three in total) and the set of sensitivities (i.e. over-procurement period,

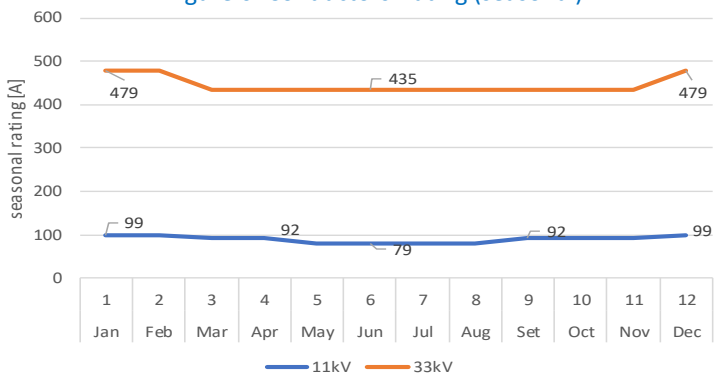
utilisation payments, NPV time horizon) used to analyse the CBA results. Section five discuss the data collection and key assumptions. Section six discusses the results of the CBA for each of the constrained lines. Section seven concludes.

3.2 Methodology for estimating flexibility requirements

The power system analysis was performed using the GridOS IDP tool[1]. It was conducted for the period 2026-2035 on a specific network area around the Inverlochy primary substation (Fort William region)[2]. The selection of the period (i.e. 10 years) is aligned with the GridOS IDP tool processing capability. The tool required key inputs such as load and generation schedule profile forecast[3] in order to identify network violations over the period under evaluation. As a result, thermal constraints were identified by SSEN in a set of 11kV lines/feeders: 724013 (3 lines), 724014 (3 lines), 724016 (1 line); and in 33kV line/feeders: FORW (2 lines); all this with 1-hour granularity[4]. The start of the violation events (i.e. date) and number of them (i.e. hours per year) vary depending on the feeder and its respective lines, with November being the month with the highest level of exceedances. It is important to note that the thermal constraints in all the cases are driven by the exceedance in load/demand over the rating capacity of the assets in evaluation (i.e. conductors), in line with the load forecast figures depicted in Fig. 1. This type of thermal constraint is also referred as "import constraint", for further details see NGESO (2018).

We received information from SSEN on the likely thermal violations in the set of lines mentioned above. Only two of them were selected for performing the CBA, one at 11kV and the other at 33kV. Thermal violation data provided by SSEN was then adapted considering the conductors' seasonal ratings in both lines, see Figure 3 for details. The use of seasonal ratings increased on average the size of flexibility requirements per year. This is explained by the inclusion of lower seasonal ratings in the analysis, which are mainly observed in summer.

Figure 6: Conductors' rating (seasonal)



Source: SSEN

[1] https://project-merlin.co.uk/wp-content/uploads/2021/02/1.07-Grid-OS-IDP-Configuration-and-Development.pdf

[2] The other two are Mallaig and Pinegrove, but these were not included in the CBA analysis.

[3] Load and generation schedule profiles were estimated using data provided by Regen (i.e. projected EV units adoption, EV load profiles, heat pump capacity adoption and rooftop solar generation capacity, etc.) and other historical data (hydro, representative load and generation schedule profiles). For further details see Part 2 of the Milestone 6 report.

[4] This means that 8,760 timeframes were evaluated per year and feeders (and their respective lines). The selection of 1 hour granularity was by choice to simplify the power system analysis, lower granularities are also possible (i.e. 1/2h).

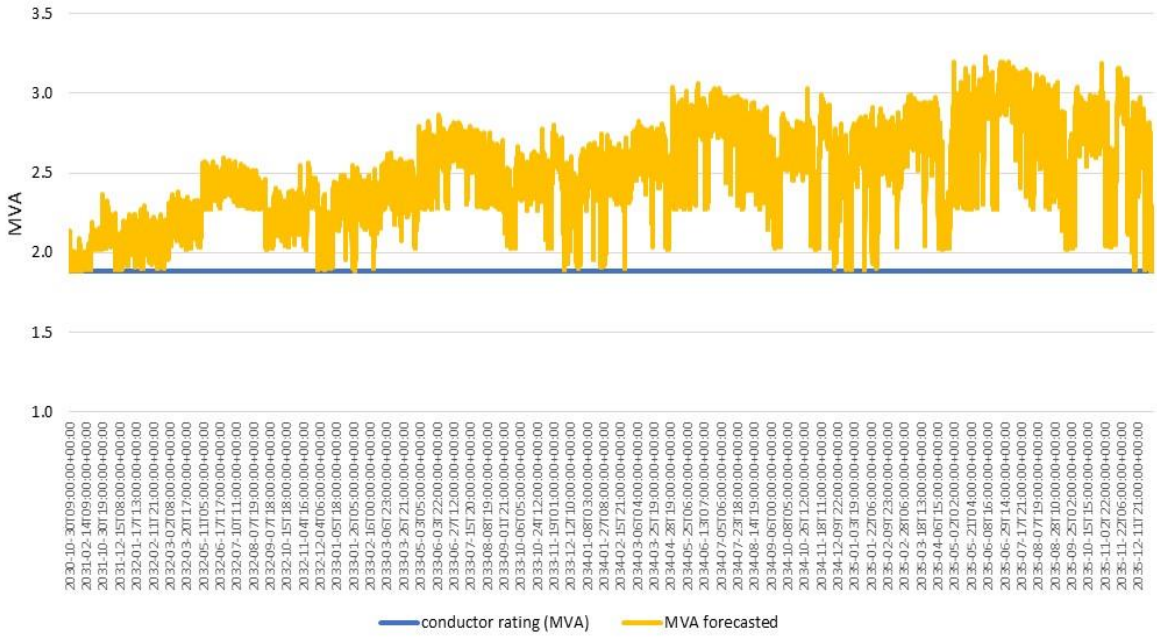
It is important to emphasize that the analysis was made using a realistic approach. This means actual power flow under normal operating conditions (i.e. consideration of both load and generation) was assumed. Accordingly to SSEN, this approach is not currently applied by them but in the future, there is a chance to adopt it if there is enough liquidity in the market, then week-ahead procurement could be the norm by 2026. Based on this statement, we have assumed that only utilisation payments will be paid to flexibility providers, see section 4.2 for further details of the sensitivities regarding this payment. A worst-case approach (i.e. identification of peak demand with zero generation) is currently used by the DNO as the traditional method for system planning (with a traditional reinforcement solution to accommodate the forecasted load) and for estimating the service windows required for contracting flexibility services (4-year contracts) under the current Constraint Managed Zone scheme (i.e. via Piclo Flex)[5].

The flexibility requirements associated to the 11kV and 33 kV lines/feeders are discussed in the next two sub sections. Technical specifications of these assets (current and new conductors) are described in Appendix 1.

3.3 Flexibility requirements in 11 kV line

Figure 4 depicts the expected trend of violation events (i.e. thermal constraints) for the 11kV line. In this case, violations start in November 2030. The flexibility requirement (MWh) is represented by the area above the blue line or conductor rating (=MVA*power factor*hours) and under the orange curves, with a total of 17,550 MWh to be required for the whole period (2030-2035). The maximum violation happens in June 2035, with an overload sized at 189% of the rated current [I].

Figure 7: Flexibility requirement per timeframe, 11kV line (2030-2035)



[5] The difference between the first and the second one is that in the traditional method the highest peak demand is evaluated (i.e. one 1/2h period in winter). In the second case a similar procedure is followed but using historical data instead (which is scaled up considering the same load growth assumptions used in the traditional one).

A closer view of these events is shown in Table 1. By 2035, this line will be constrained most of the time, around 90% (= 7932/8760), however the average size of flexibility required per timeframe or hour, remains relatively small (0.82 MW/h) with an average peak of 1.33 MW.

Table 1: Flexibility requirement per year, 11kV line (2030-2035)

year	min (MVA)	max (MVA)	total (MWh)	hours	average MW/h per year
2030	0.15	0.25	2.62	15	0.17
2031	0.01	0.48	179.70	1364	0.13
2032	0.01	0.71	2022.64	5531	0.37
2033	0.01	0.98	3711.11	6528	0.57
2034	0.01	1.18	5164.02	7128	0.72
2035	0.01	1.34	6469.11	7932	0.82

3.4 Flexibility requirements in 33 kV line

The violation events in the 33 kV lines are depicted in Figure 4. The first thermal constraints are observed in November 2032. This line is much less constrained than the 11 kV one, which is reflected in the total number of MWh expected to be procured, around 975 MWh for the period 2032-2035. The largest thermal violation happens in November 2035 this time, with an overload sized at 155% of the rated current [I].

Figure 8: Flexibility requirement per timeframe, 33 kV line (2032-2035)

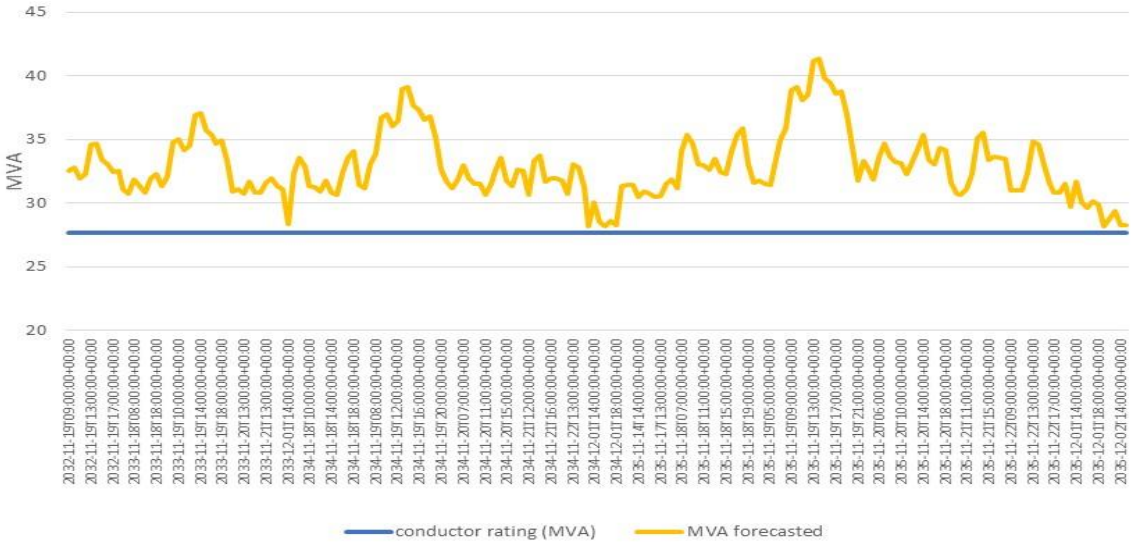


Table 2 provides more granular information. By 2035 the line will not be constrained most of the time, flexibility would be required only for 93 hours (out of 8760). However, the average size of capacity required seems relatively high (5.26 MW/h), with an average peak of 13.16 MW. Then, aggregated capacity or large-scale generators (i.e. over 5 MW) and/or controllable loads, will be required to meet the flexibility requirements.

Table 2: Flexibility requirement per year, 33kV line (2030-2035)

year	min (MVA)	max (MVA)	total (MWh)	hours	average MW/h per year
2032	3.41	7.03	54.71	11	4.97
2033	0.68	9.43	143.53	30	4.78
2034	0.50	11.48	287.74	60	4.80
2035	0.55	13.72	489.23	93	5.26

3.5 Cost Benefit Analysis Methodology

The CBA methodology used in this report is aligned with the CEM CBA tool developed by Baring for the Energy Networks Association – ENA (Baringa, 2020). This tool was built based on the Ofgem CBA tool for network investment decisions, which was created to have a common approach in the evaluation of DNOs business plans.

The CBA allows to compare different models of intervention including traditional (BAU solutions) ones and alternative network intervention ones such as the procurement of flexibility services from generators, storage units, controllable loads. The CBA estimates NPV of the different models of intervention in a specific time horizon (i.e. lifetime of the assets involved). A straight-line depreciation approach is used, then network assets are assumed to be depreciated gradually over their useful economic life (set at 45 years). Capitalisation assumptions are applied to financial costs (Ofgem, 2021).

The benefits are given by the NPV difference of the BAU or traditional solution and other alternative options. In this study, the BAU solution implies the upgrade of the conductors, 11kV and 33kV, in the presence of thermal constraints, which start in 2030 and 2032 respectively, as explained in the previous section. The alternative network intervention is given by deferring for 1 or more years the upgrade of the asset and contracting flexibility services during those years to deal with the constraints. The analysis is made separately per each type of asset.

In the evaluation of the options, different value streams are assessed in line with the framework described in 1.06 Flexible Service Valuation Mechanism (SSEN, 2020). The consideration of these value streams depends on the type of constraint and proposed solution(s), then only the most relevant to this study have been included. In addition, some of the value streams may be applicable only to the BAU solution or to the alternative network interventions, while others are relevant to both. These are summarised in Table 3.

The time horizon for the analysis is up to 2073 and 2075 in line with the lifetime of the conductors (11kV and 33kV), with the evaluation of intermediary years. All the values are in 2018/19 prices[6] and all costs and benefits are discounted using the social time preference rate (STPR) defined in the HM Treasury Green Book. For further details about data collection and values see Section 5. Thus we are undertaking a social cost benefit analysis (SCBA).

[6] Use of Retail Price Index (RPI)/Consumer Price Index Home (CPIH) combined approach instead, which is consistent with the RIIO-ED2 Business Plan Data Template and ED2 Financial Model inflation methodology (Ofgem, 2021).

Table 3: Summary of value streams used in the CBA

Value stream	valuation	Relevant to: *BAU*	Relevant to: *alternative options*
(1) Short term flexible service valuation	Traditional reinforcement NPV Compares the NPV of the BAU solution with the NPV of deferring the conductor upgrade for one or more years and contracting flexibility services instead (for the same number of years). This involves two costs: reinforcement costs and bid costs (i.e. utilisation payments)	yes	yes (with investment deferral)
	Network losses The impact of network losses is estimated in both, the BAU solution and the alternative option. Use of standardised value in agreement with RIIO ED Ofgem CBA tool.	yes	yes
	Flexibility service administration and management costs Related to the administrative costs incurred by the DNO to procure flexibility services, an annual cap is suggested based on SSEN current practices.		yes
(2) Future flexible service valuation, *plus all costs/savings in (1)*	Net avoided outage costs (asset health) This captures the impact of asset failure in relation to (1) customer interruptions (CI) and duration of interruptions (CML) for the 11 kV conductor; and to (2) the amount of load at risk for the 33kV conductor with the consideration of value of lost load (VoLL). These costs are then multiplied by the probability of failure, in line with the DNO common network asset indices methodology.	yes	yes
(3) Future plus flexible service valuation, *plus all costs/savings in (2)*	Community generation credit This values the contribution of community generation in the provision of flexibility services. This is introduced as a negative costs in the scenarios that involve flexibility services, see Section 5 for details.		yes
	Net avoided greenhouse gasses (GHG) This refers to the costs of carbon emissions associated to network losses. Conversion factors (from Defra) and price carbon central (from BEIS) were used.	yes	yes

3.6 Scenarios

The CBA involves three scenarios:

Baseline (Scenario 0):

This scenario represents the BAU. It refers to the upgrade of the two conductors, 11kV (in 2030) and 33kV (in 2032) due to thermal constraints. It also considers the costs of power losses and network performance cost of failure (which considers costs related to customer minutes lost (CML), customer interruptions (CI) and value of lost load (VoLL)[7]) before and after the conductors' upgrades. For instance, considering the period 2026-2035, under the BAU solution the current 11kV conductor

[7] VoLL is a representation of the value that customers place on security of supply (Ofgem, 2020).

would be used until 2029 and the 33kV one until 2031, with the new ones to start operating in 2030 and 2032, respectively.

Scenario 1:

In this scenario flexibility services are contracted to deal with thermal constraints on both conductors. This allows SSEN to defer the conductor upgrades for one or more years. Flexibility service providers get paid for this via utilisation payments in line with the sensitivity analysis explained below. Flexibility procurement costs incurred by SSEN are also added. Similar to the previous scenario, the cost of power losses and network performance cost of failure are also included. During the year(s) that flexibility services are contracted, a slight reduction in power losses is noticed and reflected in the cost benefit analysis.

Scenario 2:

This scenario is like Scenario 1 with DER providing flexibility services, with the consideration of investment deferral, impact of power losses and network performance cost of failure but including societal costs or benefits. Among there are emission costs due to power losses and community generation credit.

Table 4 summarises the three scenarios.

Table 4: Summary of scenarios

Scenario	Business as Usual (*)	Flexibility services from DER	Societal benefits/costs	Cost/benifit figures considered in the CBA
S0	yes			reinforcement costs, power losses, network performance costs of failure
S1	yes (with deferred investment)	yes		all the above plus bid costs (availability payments & procurement costs)
S2	yes (with deferred investment)	yes	yes	all the above plus CO2e associated with losses, community credit generation

(*) this refers to the realistic case

3.7 Sensitivity Analysis

A set of sensitivities were selected for analysing the value of deferring the conductor upgrades, a central case is also proposed. This includes the over-procurement factor, utilisation prices and the use of different time horizons to estimate the cash flow of the options described in each scenario.

The over-procurement factor is used mainly to account for the risk of non-delivery or reliability of delivery rather than for uncertainty on the forecasted MVAs above the conductors' rating capacity. Three values have been proposed, with a maximum value of 15%[8].

[8] SSEN is currently working on the risk matrix to decide whether over-procurement is required for the Sustain CMZ flexibility services (currently procured via Piclo Flex). A maximum rate of over-procurement (set at 20%) is being evaluated. Then, we consider that 15% is a sensible figure, especially if we refer to future procurement (by 2030).

The requirement of flexibility services is based on the realistic case with potential procurement of flexibility in the short term (i.e. no more than week ahead) rather than in the long term (i.e. many weeks, months, or years ahead). The realistic approach means that there is more certainty in terms of when and for how long (with 1 hour resolution timeframe) the rating capacity of the conductors will be exceeded and the size of flexibility required to deal with this. We have also assumed that by the 2030s there will be enough liquidity in the market for contracting flexibility, from different sources including generators, storage units and controllable loads. Then, compensating flexibility providers for utilisation only, which means just for MWh delivered, seems sensible. The utilisation payment for the central case has been set at £50 MWh (2018/19 prices) which is equivalent to the average GB wholesale electricity prices in day-ahead market for the period 2015/16-2018/19[9]. The other two sensitivities represent +/- 50% of the central case.

In relation to the time horizons, we consider three moments to evaluate the discounted savings. The last one, 2073 (11kV conductor) and 2075 (for 33kV conductor), captures the full economic life of the asset (set at 45 years). The difference is explained by the fact that in the case of the 11kV conductor, the thermal constraints appear two years in advance relative to the 33kV one.

The following table describes the sensitivities.

Table 5: Summary table of sensitivities covered in the CBA

Sensitivities	Central Case	Range of values analysed
over-procurement factor (OPF)	7.5%	0%, 7.5%, 15%
utilisation price	£50/MWh	25, 50, 75 £/MWh
NPV (year)	2050	2040, 2050, 2075

3.8 Data Collection and Assumptions

Data has been collected from different sources. SSEN provided most of the data for the period in evaluation (2026-2035), including flexibility requirements per each of the lines (11kV and 33 kV) with 1 hour granularity, seasonal ratings (which we used to re-estimate the flexibility requirements), reinforcement costs (associated with the BAU solution to solve the thermal constraints: conductors' upgrade with higher ratings), network losses in 11kV and 33kV for both the current/old and new conductors (which helped to value the impact of network losses and CO2 emissions due to losses), age of conductors/cables (for the estimation of probability of failure), among others.

We also collected data from Ofgem to value losses, CML, CI and VoLL. Key financial assumptions were also made based on Ofgem (2021), including capitalisation rate, depreciation mechanism (linked to the asset lifespan), etc.

The most relevant source for valuing network performance cost of failure is the DNO common network asset indices methodology (GB DNO-NIE, 2021). The methodology to value the cost of failure depends on the type of asset (i.e. LV&HV or EHV&132kV assets).

[9] The average value is estimated at £49.25/MWh, for simplicity we have assumed £50/MWh. Electricity prices day-ahead (monthly average) can be found at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators.

In terms of the societal costs/savings, we collected data regarding carbon price from BEIS (2019),GHG conversion factors from Defra (2021) and calculated community generation credit i.e. Where households are incentivised via payments to generate renewable energy. Regarding the community generation credit, we have estimated a value of 0.5p/kWh. This credit reflects the value of localism attributable to community generation. It is not currently used within the UK but it was promoted a time ago and is used in other parts of the world. We have used evidence of the impacts of community generation credits from CESP - the Community Energy Savings Programme which ran from 2009-2012 (DECC, 2014) and the respective legislation[10] in order to determine the value of 0.5p/kWh.

Appendix B providers further details about data collection, sources and assumptions associated to each value stream (described in Section 3).

3.9 Results and Discussion

This section discusses the results of the CBA for 11kV and 33kV lines. The value of reinforcement deferral is evaluated only for the first four years in both cases, due to the lower/negative values of cumulative NPV observed after that, which means no savings at all.

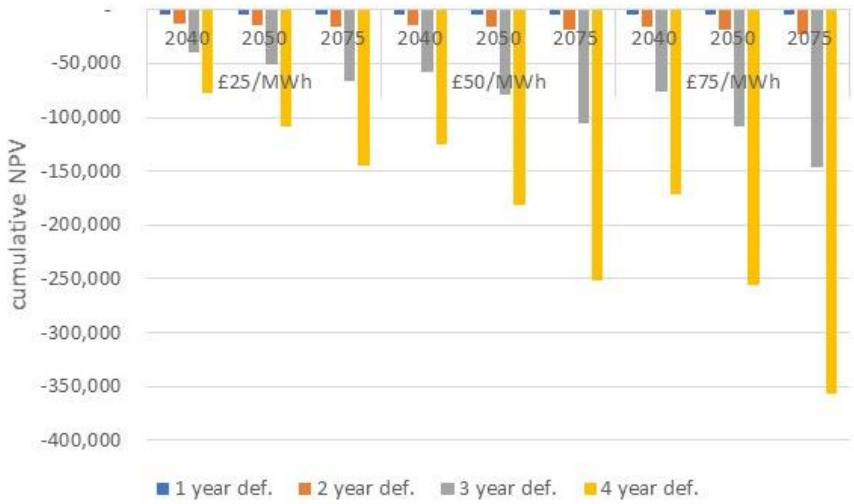
3.9.1 11kv Line

3.9.1.1 Baseline versus Scenario 1 (S0-S1)

The procurement of flexibility services as an alternative to deferring the upgrade of the 11 kV conductor, does not bring value. From Figure 5, we observe that the cumulative NPV is negative in all the cases. Losses can be up to £0.36m by 2075. One of the reasons behind this is the use of the realistic approach in the power system analysis, explained in Section 2. This realistic approach requires much lower levels of investment (around £30k in this case) in comparison with those that are based on worst-case scenarios (i.e. max demand and zero generation), which is currently the norm. On the other hand, the number of violation events is very high here (see Table 1). This means that flexibility services would be continuously required, especially in 2035 with around 8000 hours; consequently flexibility procurement costs increase importantly (around £0.52m in 2035).

Figure 9: SO versus S1 (OPF=7.5%), 11 kV line

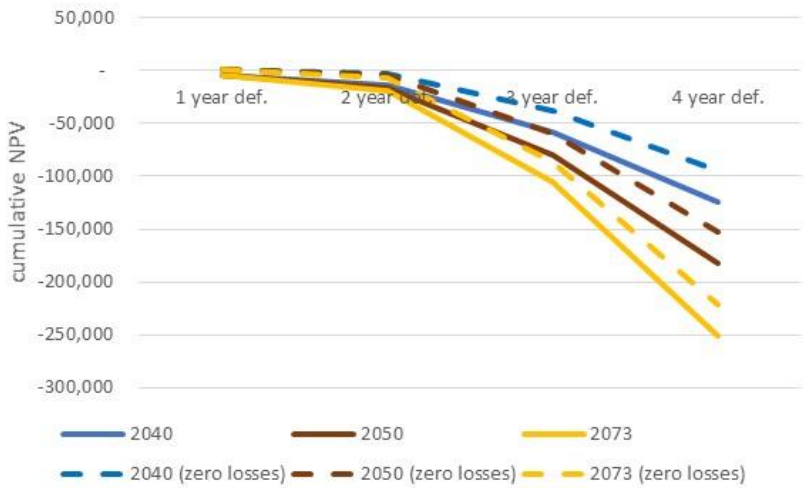
[10] https://www.legislation.gov.uk/ukdsi/2009/9780111481929/contents



The increasingly negative NPV evaluating beyond 2040 happens for two reasons. First, because we are adding more discounted cash flow when we extend the time horizon. In addition, the negative gap (i.e. NPV differences) is bigger because we are not just deferring the investment (for 2 years for instance) but also contracting flexibility for these 2 years, which can be very expensive depending on how much we contract and the price for this (this is the case of the 11kV line for instance).

Another interesting observation is related to the type of upgrade that is required under the BAU approach. In this case, it was suggested an upgrade of the 11kV conductor only, with 41 years of service life by 2026. The new proposed 11 kV conductor has a higher rating (55% extra) than the current one. This, as expected, is having an impact on network losses, because losses in the new conductor will be much lower (see Appendix A for details). Then, if we exclude the impact on network losses, we will expect an increase in the NPV. This is because, during the years that we defer the upgrade, we will continue using the current conductor (with high and increasing network losses) and contracting flexibility. Figure 6 confirms this, however most of the time the cumulative NPV continue being negative, excluding figures from 1 year deferral. Looking at the central case, the cumulative NPV varies between £1k (1 year deferral) and -£152k (4-year deferral), in comparison with the previous approach, -£4.2k and -£182k, respectively. It is also noticed that the value of network performance cost of failure is very low and does not produce any significant impact on the cumulative NPV.

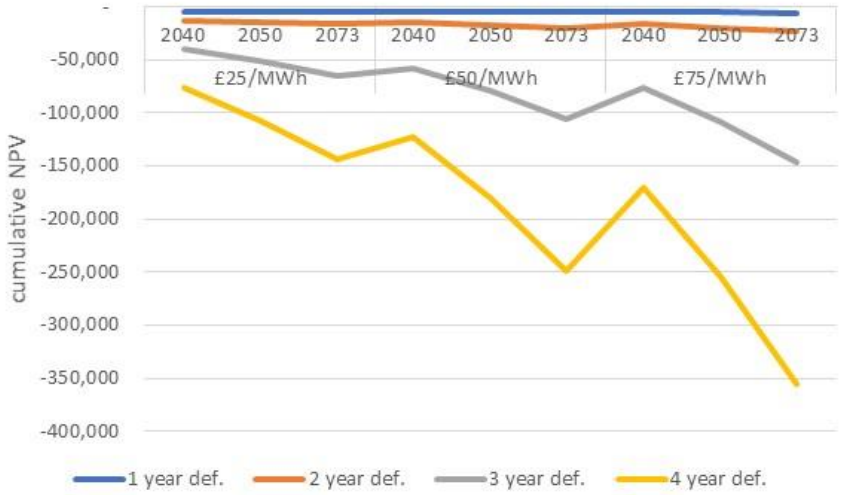
Figure 10: S0 versus S1 excluding network losses (OPF=7.5%, UP=£50/MWh), 11 kV line



3.9.1.2 Baseline versus Scenario 1 (S0-S1)

D) The introduction of societal costs/savings does not increase the cumulative NPV, except for the 4-year deferral option, as we can see from Figure 7, however the cumulative NPV figures remain negative in all the cases. There are two societal variables in S2, community generation credit and cost of carbon emissions due to network losses. While the first one reduces the costs of contracting flexibility (acts as a credit), the second one increases it because network losses remain higher (in contrast with the new conductor). At the beginning, the cost of carbon emissions due to network losses drives the lower value of cumulative NPV, however at the end of the period (2035), community generation credit are the ones that drive the savings (the more flexibility contracted the more the size of the credit). In contrast to the impact of network losses, the introduction of societal costs/savings to the CBA has a small impact in the cumulative NPV, with an average variation of 4.5% for the central case.

Figure 11: SO versus S2 (OPF=7.5%), 11 kV line



3.9.2 33kv Line

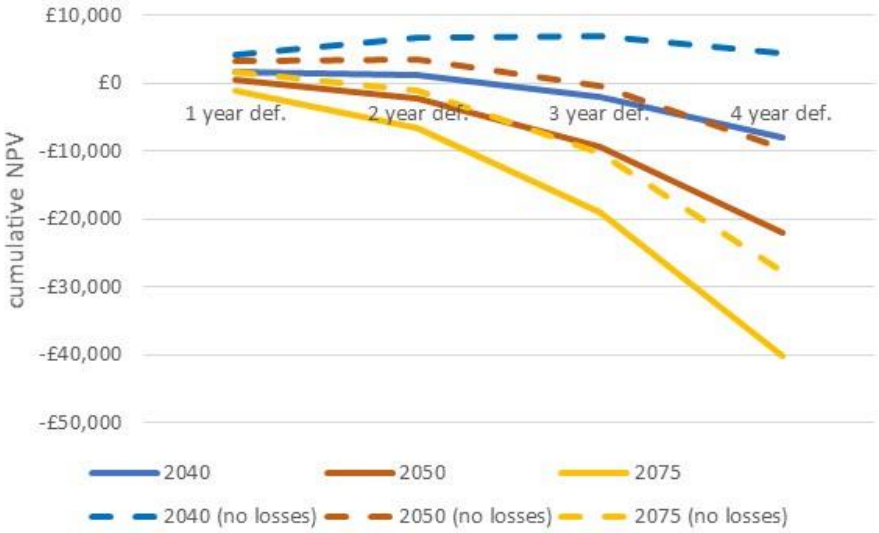
3.9.2.1 Baseline versus Scenario 1 (S0-S1)

Savings from procuring flexibility as an alternative option of network investments are still very low or non-existent, even with the consideration of UP=£25/MWh, with a maximum saving of £2.7k for a 2 year deferral by 2040, see Figure 8. Most of the rationalities explained in Section 6.1.1 apply here with some exceptions. In this case, we have larger reinforcement costs and a smaller number of violation events, see Table 2.

Figure 12: S0 versus S1 (OPF=7.5%), 33 kV line

Figure 9 depicts compare the cumulative NPV with and without the consideration of the network losses. As expected, and similar to our findings in 6.1.2, savings increase. By 2040, savings are observed across the whole set of reinforcement deferral durations (see blue dashed line) with a maximum cumulative NPV of £6.8k (for a 3 year deferral). In the central case, the optimal reinforcement deferral duration is the 2 year one, with savings around £3.4k.

Figure 13: S0 versus S1 excluding network losses (OPF=7.5%, UP=£50/MWh), 33 kV line

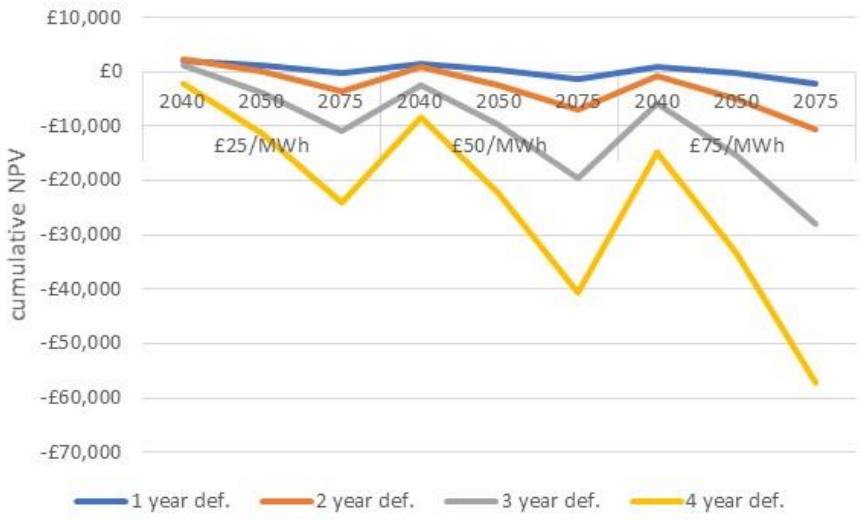


When the impact of over procurement was analysed, we observe a higher value. This time, a 0% or 15% OPF produces an average change of around 12.4% for the central case.

3.9.2.2 Baseline versus Scenario 2 (S0-S2)

E) When the societal savings/costs are included in the analysis, the cumulative NPV is reduced slightly across all the time horizons and deferral durations. For the central case, the reductions are between 36% (1 year deferral) and 2 % (4 year deferral), see Figure 10.

Figure 14: SO versus S2 (OPF=7.5%), 33 kV line



3.10 Conclusions

A CBA has been performed to analyse alternative interventions to deal with thermal constraints in the Fort William region. These interventions require the procurement of flexibility services. The conventional solution suggests an upgrade in the current conductors. We are evaluating the deferral of replacement conductors, where the existing conductors are performing poorly and where the cost of replacement is low (due to the use of the realistic approach for the power flow analysis, rather than the worst case one). Clearly with better performing existing conductors and more expensive replacement assets the situation might be different. We are also modelling a situation where the requirement for flexibility is high and hence the operational cost of this is also high.

An alternative setting where the quantity of flexibility required was low and the existing assets were performing better would make the NPV of a flexibility solution higher.

Overall, however our analysis reveals that the sweet spot – if it exists – of where a flexibility solution is to be favoured deep in the distribution grid is quite small. Under a wide range of possible situations it may not exist. Note that we have not attempted to put a cost on the running costs of the flexibility procurement mechanism itself

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4 Appendix A: Conductor specifications and power losses

11kV conductor						Annual Losses [MW]					
	Voltage kV	Feeder	Length [m]	Material	Metric Size	2030	2031	2032	2033	2034	2035
Actual Conductor	11	724014	1393.83	CdCu	12 mm2	268	352	451	561	665	753
Proposed Conductor	11	724014	1393.83	Cu	32 mm2	134	176	225	281	332	376

33kV conductor						Annual Losses [MW]					
	Voltage kV	Feeder	Length [m]	Material	Metric Size	2030	2031	2032	2033	2034	2035
Actual Conductor	33	FORW	1200	Cu	185 mm2			144	169	191	215
Proposed Conductor	33	FORW	1200	Cu	400 mm2			71	83	94	105

5 Appendix B: Variables, sources and assumptions for the CBA

Value stream	Concept	**Values** (monetary figures in 2018/19 prices)	Notes/Sources
Short term flexible service valuation	reinforcement costs (realistic case)	£ 30k (11kV), £168k (33kV)	Provided by SSEN, upgrade work to be done in 2 years.
	type of asset (to upgrade)	11kV: overhead conductor, 33kV: underground cable (non-pressurised)	Provided by SSEN, with technical specifications.
	flexibility requirements	see Figures 4, 5	Provided by SSEN, 1 hour timeframe (2026-2035).
	bid costs (utilisation prices)	25, 50, 75 (£/MWh)	Own assumptions, see sensitivity analysis, Section 4.
	over-procurement factor	0, 7.5%, 15%	Own assumptions, see sensitivity analysis, Section 4
	power factors (conductors)	0.996 (11kV), 0.96 (33kV)	Provided by SSEN.
	seasonal ratings	see Figure 2	Provided by SSEN.
	assumed asset life	45 years	Ofgem (2021), same asset life for both type of assets.
	network losses	see Appendix A	Provided by SSEN.
	value of losses	£56.07/MWh	Ofgem (2021).
	Flexibility service admin&manag. costs	£16.67/h procured/year, up to £8513 per year	Fixed value provided by SSEN, ratio from NGESO (2021) based on procurement costs at dist. (£30k/year for 1,800 hours).
Future flexible service valuation	CML, CI, VoLL	£0.44/minute lost, £17.88/interruption, £21,000	Ofgem (2020, 2021).
	age of conductors by 2026	41 years (11kV), 57 years (33kV)	Provided by SSEN.
	normal expected life	60 years (11kV), 100 years (33kV)	From GB DNO-NIE (2021), Table 20.
	number of connected customers (2026-2035), 11kV line only	11kV: 1218 (2026), 1293 (2035)	own estimations using SHEPD average annual growth (2009/10-2020/21): 0.7% , Ofgem (2018), SSEN (2019).
	probability of failure curve parameters	k-value: 0.0080% (11kV), 0.0658% (33kV), c-value: 1.087	From GB DNO-NIE (2021), Table 21.
	reference network performance cost of failure for 11kV line (LV, HV assets)	several parameters	From GB DNO-NIE (2021), Table 233.
	reference network performance cost of failure for 33kV line (EHV & 132kV assets)	several parameters	From GB DNO-NIE (2021), Table 235.
Future plus flexible service valuation	community generation credit	5p/kWh	own assumption, based on evidence from previous Community Energy Service Programme (CESP) in GB; DECC (2014), Electricity and Gas Order 2009. It represents what the society is willingness to pay for the community aspect of an energy project, on top of pure environmental aspects.
	capacity shared of community generation	20%	own assumption.
	CO2 conversion factor for electricity	193 (2026), 124.4 (2035) g CO2e per kWh	From Defra (2021), it considers both electricity generated & T&D grid losses. Assumptions: power sector emissions to be reduced to 10g/kWh by 2050, linear decarbonisation pathway from 2021/22 until 2050.
	traded carbon prices	21.07 (2026), 31.41 (2035) £/t	From BEIS (2019), short-term prices for modelling purposes.
Others	RPI, RPI&CPIH (combined)	several values	Ofgem (2021)
Rates, capitalisation, others	pre-tax WACC	3.6%	Baringa (2020).
	social time preference rate (STPR	3.5% (<30 years), 3% (>30 years)	HM Treasure (2020).
	capitalisation rates	85%	Default value suggested by Ofgem (2021).
	NPV time horizons	2040, 2050, 2073/5	See sensitivity analysis, Section 4.

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