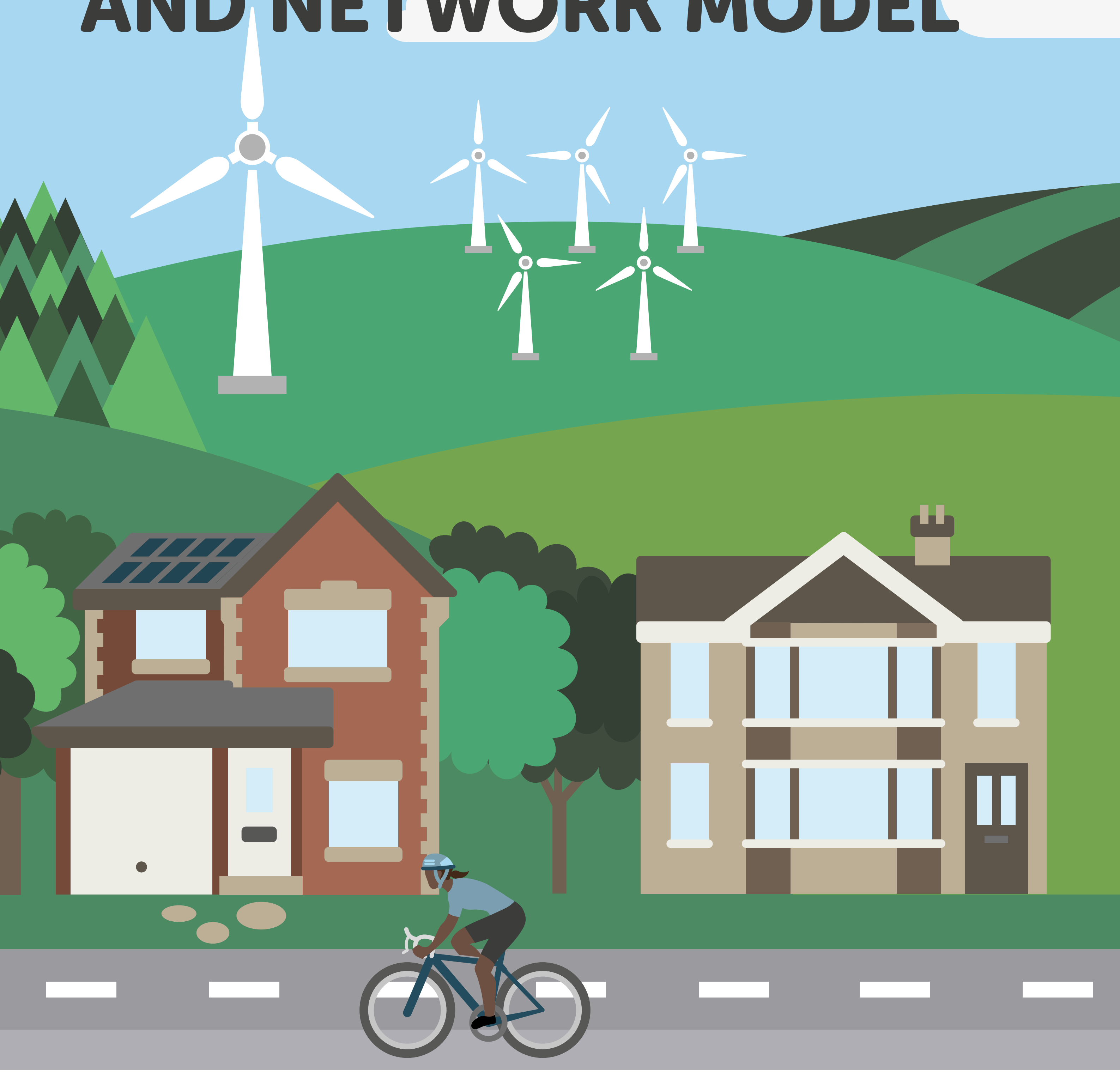
SDRC 8.5 and 8.6

PRICING MODEL, CUSTOMER MODEL AND NETWORK MODEL



SAVE

Solent Achieving Value from Efficiency

Scottish & Southern Electricity Networks

Solent Achieving Value from Efficiency

Solent Achieving Value through Efficiency (SAVE) is an Ofgem funded project run by Scottish and Southern Electricity Networks (SSEN) and partnered by the University of Southampton (UoS), DNV GL and Neighbourhood Economics (NEL). The innovative programme evaluates the potential for domestic customers to actively participate in improving the resilience of electricity distribution networks and thereby defer the need for traditional reinforcement. The government has forecasted an increase in electricity demand of 60% by 2050 meaning peak demand is likely to grow to six times higher than what the network was designed for.

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EXECUTIVE SUMMARY

The Solent Achieving Value from Efficiency (SAVE) project is a Low Carbon Network (LCN) Fund project which is being led by Scottish and Southern Electricity Networks (SSEN) in partnership with DNV-GL, University of Southampton (UoS), Future Solent, Neighbourhood Economics and EA Technology.

The project aims to trial and establish to what extent domestic demand side response measures can be considered as a cost-effective, predictable and sustainable tool for managing peak and overall demand as an alternative to network reinforcement.

The SAVE projects Network Investment Tool (NIT) runs a database of five years worth of research in a Distribution System Operator (DSO) ready software interface. The data powering the NIT includes domestic monitoring of 4000 homes across the Solent (and substation monitoring of another 4000 homes), each paired with demographic information to understand how different types of household use energy and interact to different forms of stimuli. Households were engaged with a range of domestic demand side response (DSR) approaches, including energy efficiency, data-informed engagement, price signals and community coaching.

The NIT delivers a means of modelling Low Voltage (LV) networks by using census information to represent types of customer on given networks. This provides the DSO with a more granular insight into capacity analysis on a substation, across the day, and hence availability for new connections (referred to as the tools **'single-scenario'**). By running load-forecasts on the network a DSO can then start to understand how low carbon technology (LCT) uptake may affect said network over a 40-year time span. This can highlight to network planners when their networks may require management (year) as well as at what season and time of the day (referred to as the tools **'future-scenario'**). Finally, the NIT's load-flow engine provides a planning department with the ability to run up to four network scenarios simultaneously to provide a spread of potential future scenarios. By pairing this information with a commercial interface the tool offers three strategies per scenario on how to manage the network over time. These strategies compare the cost of smart, SAVE and traditional reinforcement options as well as the capacity they may offer and the NPV of intervention deferral. Regret analysis is used to highlight to planners which strategy may be best placed to manage the network in the face of future uncertainty and when they are likely to need to intervene in network management (referred to as the tools **'multi-scenario'**). The idea being the tool will allow more informed planning forecasting, more cost-effective network management and identification of where/when smart (including SAVE) interventions may be applicable over traditional measures of network management.

By better modelling LV networks, the report suggests a DSO could use the tool to build-up a 'watch-list' of their networks, keeping track of capacity as different scenarios of LCT uptake emerge. Once management is required, by using the NITs commercial analysis DSO's could quickly and easily assess whether smart is likely to be able to compete with traditional measures in network management, supporting in the network operator's commitment to test flexibility solutions on reinforcements of significant value (ENA, 2018). This could help to better inform a DSO where it might want to run a Constrained Managed Zone (CMZ), or Social Constrained Managed Zone (SCMZ)[1].

The NIT runs on three main models developed throughout the SAVE project:

- A Customer Model developed by the University of Southampton.
- A Network Model developed by EA Technology
- A Pricing Model developed by EA Technology

This report focuses on how each of these models interact to provide the outputs defined above and how a distribution network operator (DNO) may wish to use different parts of the NIT across different departments/for differing purposes in their evolution to a DSO.

1 The SCMZ is SSEN's evolution of CMZ's which aims to open flexibility market procurement to SMEs and local organisations. SCMZ's look to achieve this through: visibility of flexibility markets, open procurement mechanisms, tender application support processes (through seed-funding and/or consultant expertise) and weighting social factors within to tender assessment

1

INTRODUCTION

1.1 Background

The government's smart systems and flexibility plan (Ofgem, 2017) demonstrates a clear requirement for distribution network operators (DNO's) to transition to the role of wider system operation. Growth in electric vehicles (EV's), low carbon technologies (LCT's) and electrification of heating are all changing the demands on our electricity systems. The evolution of the way in which we use electricity in our homes and businesses signal a more multi-directional electricity market with power not just flowing from large-scale generation sites to customers' homes and businesses, but from homes and businesses back up the network, across communities and into varying forms of storage. DSO's have an important role to play in balancing this evolving system to facilitate consumers' needs and government targets such as those outlined in the carbon plan.

With the growth of greater requirements on the electricity system, new solutions and technologies are emerging to help both customers and industries best manage their electricity usage. Likewise, DSO's need to develop new ways of monitoring, modelling and managing their networks[2]. The SAVE project has focused explicitly on how DSO's can evolve to better understand and support the appetite of domestic customers to provide demand reduction mechanisms, specifically at low voltage (LV) levels of the network, the benefits of which can be aggregated to higher voltages. The SAVE Project bid document estimates that without smart management the cost of reinforcing low voltage assets in SSEN's southern (SEPD) and northern (SHEPD) license areas could be £3 billion (2014).

The SAVE project has monitored over 8000 customers in the Solent for up to three years. 4000 of these customers were monitored at substation and feeder level in SAVE's community energy coaching trials (see SDRC 8.8) led by project partners Neighbourhood Economics, a further 4000 were monitored at household level. The 4000 household monitors on SAVE were deployed across the Solent within homes representative of the areas wider population and were subject to a randomised control trial (RCT) methodology designed by project partners: The University of Southampton (UoS) (see SDRC 2.1). The project trialled three further (additional to community coaching) methods of engagement designed by project partners DNV GL, including energy efficiency, data-informed engagement and price signals.

The wealth of data from SAVE's trials have fed into a series of three models; the Customer Model, the Network Model and the Pricing Model. When operating in sequence these three models provide DSO's with a functioning Network Investment Tool (NIT) which "allows DNO's to assess and select the most cost-efficient methodology for managing a network constraint" (SAVE bid document, 2014). The SAVE project has produced a series of eight Successful Delivery Reward Criteria Reports (SDRC's) evidencing the build and outcomes of this modelling package of work.

SDRC's 2.1-2.3 have shown the evolution in development of the SAVE Project's customer model (developed by UoS) and act as evidence to the creation of the Customer Model as well as the model's functionality in isolation from the wider models and the NIT. SDRC's 7.1-7.3(/8.5) have shown the evolution of the projects network model (developed by EA Technology) and act as evidence to the creation of the Network Model and (in SDRC 7.3/8.5) the Pricing Model. These reports discuss lessons learned from building a network and pricing model as well as isolated functionality much like the customer model reports. The project has also produced a report, SDRC 8.2: Network Investment Tool, showing the output of the amalgamation of the projects three models, and how this can be used by network planners to assess whether smart, SAVE, or traditional measures are best placed to manage a given network constraint.

This report (SDRC 8.5/8.6) discusses how the three models developed in SAVE interlink to create a NIT. It provides insight into the software interfaces required to stimulate each model. Likewise, this report acts as a guide for wider DSO's to understand how they could dismantle functions within the amalgamation of models termed the NIT to meet their own specific requirements.

2 New Thames Valley Visions 3 M's Model.

1.2 Report structure

Section 1: Introduces the SAVE methodology and modelling work;

Section 2: Provides an overview of each SAVE model and its purpose;

Section 3: Shows the data required for each element of the SAVE NIT, including each model and the interfaces that allow outputs from one model to flow into inputs of another model;

Section 4: Shows four different network assessments that can be run through SAVE's NIT, effectively by utilising each model in a different way. This includes: a single assessment of the network, a future assessment of the network, a multi-scenario assessment of the network and assessment at High Voltage/Extra High Voltage (HV/EHV) levels.

Section 5: Concludes and looks at the operation of the tool in the business as usual world of a DSO.

1.3 Project Outcomes

At the point of submission, the SAVE project identified seven key project objectives, four knowledge gaps and four learning outcomes to be addressed. Those which can be built upon through this SDRC are detailed below:

- *[Project Objective] – Evaluate the cost efficiency of each [SAVE] measure*
- *[Project Objective] – Produce Customer Model revealing customer receptiveness to measures*
- *[Project Objective] – Produce Network Model revealing modelled network impact from measures*
- *[Project Objective] – Produce a Network Investment Tool for DNOs*
- *[Project Objective] – Produce recommendations for … [an] incentives model[3] that DNOs may adopt via RIIO*
- *[Knowledge gap] – What are the most cost-effective energy efficiency measures for DNO's*
- *[Learning Outcome] – To gauge the effectiveness of different measures in eliciting energy efficient behavior with customers*

1.4 Method Definition

The SAVE project bid document (SSET206) outlines four main methods of intervention to be tested within the project. These were originally named as follows:

- Method 1 (M1) – LED engagement
- Method 2 (M2) – Data informed engagement
- Method 3 (M3) – Data informed engagement and price signals
- Method 4 (M4) – Community Energy Coaching

This, however, did not provide a reference number to the projects control group population. Throughout the delivery of the project, to ease identification of the methods being trialled, each was renamed as follows:

- Trial Group 1 (TG1) – Control Group
- Trial Group 2 (TG2) – LED Lighting
- Trial Group 3 (TG3) – Data informed engagement and price signals
- Trial Group 4 (TG4) – Data informed engagement
- Community Energy Coaching Trials (CEC or M4)

To avoid confusion and the risk of mismatch between delivery and reporting the project came to the conclusion the methods were better referred to by these names. Within this document, all interventions will be referred to under their revised names.

3 The term incentive here refers to incentives for customers to alter their energy consumption patterns. The incentive model is herein referred to as the pricing model developed by EA Technology. The pricing model does contain an incentive **module**, which uses elasticity curves to allow users to identify the payment levels required to achieve a pre-defined level of load reduction under price signal based trials. This is highlighted in section 2.3 and discussed in more detail in SDRC 7.3/8.5.

1.5 Terminology

To support reading this report it is important to note the use and definition of a series of key terms used to describe SAVE's Network Investment Tool.

DNO and DSO – Throughout this report, we refer to both Distribution Network Operators (DNO) and Distribution System Operators (DSO). The former is used when referring to the tool supporting existing processes whilst the latter refers to future business as usual processes the NIT can facilitate.

Model – an individual software package designed to provide the functionality to the DNO. SAVE has three models: A Customer Model, a Network Model and a Pricing Model.

Interface – A mechanism for integrating one model with another or the mechanism through which a user interacts with the suite of models. SAVE's NIT has two important user interfaces: the census interface and the Excel workbook through which the NIT is operated.

[The] Tool – The combination of all SAVE models, integrated and controlled through a single interface. SAVE has one tool: the Network Investment Tool (NIT).

Module – A process of operation within a model/series of models to provide a meaningful output to the user, SAVE's NIT has four main modules: single-scenario, future-scenario, multi-scenario and HV/EHV.

Scenario – A combination of low carbon technology (LCT) uptake rates expected to occur over the years up to 2060 (although users can choose an earlier end-point for studying within the tool).

Smart Solution – A non-traditional means of network reinforcement such as battery storage, including the SAVE interventions outlined in 1.4.

Strategy – An approach to addressing a network constraint using a defined methodology within the Pricing Model.

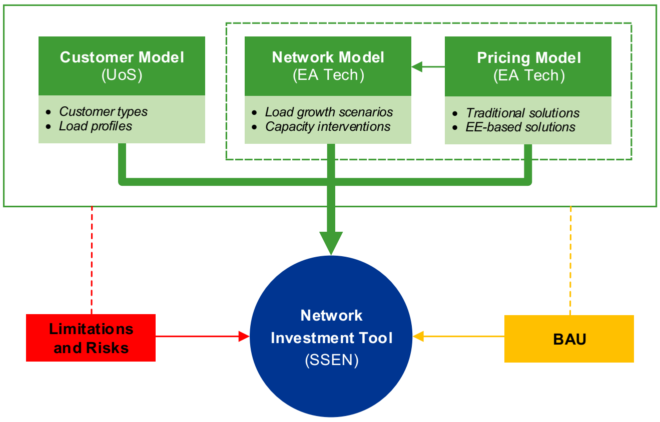
2

MODELS OVERVIEW

2.1 Individual models overview

The SAVE Project bid document, approved in 2014, outlines that the project shall produce a "Network Investment Tool that will enable DNO's to accurately select the most cost-efficient methodology for managing a particular network constraint which is most effective for its connected customer types". The way in which the project has achieved this objective is through three main models. A Customer Model developed by the University of Southampton, a Network Model developed by EA Technology and a Pricing Model developed by EA Technology. Each of these will be looked at in isolation to build a picture of each crucial interface that when interacting together perform the functions of a DSO ready NIT. Figure 1 below frames the interaction and roles of each of these models, and highlights that there are limitations and risks as well as business as usual (BAU) factors, which are discussed in more detail in SDRC 8.2 (Network Investment Tool).

Figure 1: Network Investment Tool



2.1.1 Customer Model

The role of the Customer Model is to provide half-hourly demand profiles that can be applied to the task of modelling loads on network assets. The Customer Model provides two functions:

- firstly, a number of electricity demand profiles with which to represent the 'baseline' load of a number of customer types;
- secondly, 'intervention profiles' to provide corresponding profiles with which to represent the adjusted load under intervention conditions.

The customer types have been developed to represent the different levels of demand associated with a number of household characteristics: household size (number of people), dwelling size (number of bedrooms) and primary heating type.

Profiles have been generated from household electricity demand data collected from the large-scale SAVE sample of households, aggregated according to customer type.

Intervention profiles have been generated from statistical modelling of the impact of a number of treatments aimed at reducing demand during peak hours (16:00 to 20:00) and tested using randomised controlled trials run during 2017 and 2018. The intervention profiles represent the treatment effects (change in electricity demand) observed for each customer type under the SAVE trial conditions.

In order to produce findings that can be extrapolated to the wider population of the 'Solent' Region (county of Hampshire and the unitary authorities of Southampton, Portsmouth and the Isle of Wight), the SAVE sample was designed to be representative of households within the region. The processes for sampling and the allocation of participants to treatment and control groups were also randomised to avoid the introduction of self-selection or other biases. The Customer Model therefore provides load profiles for customers that can be applied to modelling across the region. Generalising to other parts of the country outside the Solent is feasible using census information but may require some modifications to input data and assumptions.

2.2 Network Model

The role of the Network Model is to understand the capability of the low voltage network to provide an acceptable supply of electricity and how this may change over time. The Network Model is based on an existing commercially available load flow package known as WinDEBUT. The Network Model interfaces with the Customer Model to enable the network analysis to be based on the representation of customers decided on by that model, both before and after an intervention.

In addition to data from the Customer Model, the Network Model utilises records of the LV network to construct an electrical model of the LV distribution network[4]. This model allows an investigation into whether the network is delivering acceptable voltage to customers and a maximum loading upon circuits that allow voltage levels to remains within acceptable limits. The Network Model can give these insights whilst allowing for the following considerations:

- Diversity in the electrical consumption behaviour patterns of customers.
- Imbalance in the allocation of customers to phases.
- Growth of LCT within customers premises.
- The effect of customers responding to SAVE initiatives.
- The technical impact of network reinforcement schemes.
- The effect of different growth scenarios on the network outcome.

The Network Model interfaces with the user within a Microsoft Excel environment, which also contains the Pricing Model.

The Network Model provides users with the following modules:

- The Single Assessment module, used for considering base case network conditions as introduced in 4.2
- The Future Assessment module, which is used to investigate the effect of load growth and potential threats to network credibility, as introduced in 4.3

Section 3.2 describes the required data inputs for the physical layer of the Network Model and 3.2.4 describes how the Network Model accesses customer data.

2.3 Pricing Model

The Pricing Model is hosted within the same package as the Network Model. To this purpose, the Pricing Model interacts with the Network Model directly between sheets in Microsoft Excel and with the Customer Model using the same mechanisms as the Network Model discussed in section 3.2. The Pricing Model helps users understand which capacity interventions are likely to be the most effective and economic in parts of the network signalling overload warnings.

For LV systems, the Pricing Model controls the Network Model to investigate the effect of different growth scenarios on network capacity and then tests which network-led and customer-led capacity interventions are technically and then economically effective. The capacity interventions that can be tested are as follows:

- LED engagement
- Data-informed engagement
- Price signals
- Community Energy Coaching
- Reinforcement of existing feeders
- Splitting of an existing feeder (to create one new feeder, with the existing demand then shared between these two feeders)
- Uprating of source transformers
- Other smart solutions- the project has demonstrated battery storage as part of the NIT's capabilities.

Each SAVE based intervention is fed from the Customer Model's intervention profiles. This suggests how load-reduction varies based on the types of customers in a geographical area relating to the network being studied. Costs are then allocated to these interventions appropriately. For price signal interventions elasticity curves are used to determine how the response will vary based upon the amount paid (through what is known as the NITs incentive layer[5]).

4 In this case, one LV network is considered to be the HV/LV source transformer and all LV feeders fed from that source transformer.
5 See section 6.3 of SDRC 7.3/8.5- Network and Pricing Model

The economic assessment is carried out through three main strategies. These strategies are termed:

- flexibility minimum: looks favourably on traditional interventions and does not consider SAVE interventions;
- flexibility maximum: will deploy SAVE interventions in order to defer traditional interventions when they are technically viable and cost-effective; and
- all-knowing: this looks backwards in time, from a pre-set end year, to work out the most effective means to manage the network until said point in time.

The model can apply each of these strategies to up to four future energy scenarios, allowing DNOs to identify which interventions they need to be prepared to make under various future energy system pathways and, critically, when these interventions would be required.

The Pricing Model can also consider whether the non-network capacity interventions trialled by the SAVE project would be effective in resolving a forecasted overload on the HV or EHV system and whether this would be an economically efficient choice in comparison to a physical reinforcement.

3

MODELS BUILT (AND DATA REQUIREMENTS)

The below section will look at the functionality of the Customer, Network and Pricing Model in isolation as well as how information flows from one model to the next.

3.1 Customer Model

3.1.1 Data requirements

The requirements detailed in this section provide the minimum data inputs to assemble and generate the Customer Model outputs: the customer type household demand profiles and profiles which describe the change in demand due to SAVE interventions.

Household data

In order to place specific households into their customer type categories, a number of household attributes are required, including (at a minimum): household size (number of persons), dwelling size (number of bedrooms), and primary heating source (fuel). These characteristics should be supplied for all households contributing electricity consumption data. For the SAVE sample households, this information was collected and supplied by the fieldwork contractor (BMG Research) through a survey conducted with trial participants. The data file included socio-economic and demographic data for the households participating in the fieldwork. Update surveys were conducted periodically throughout the project to ensure that basic household attributes such as number of occupants were updated. A data processing script implemented within the programming language 'R'[6] assembles the appropriate survey data file by combining the original survey with the relevant update files according to the time period under consideration.

Electricity consumption data

The Customer Model requires household electricity consumption data. This was provided under the SAVE project by the projects data supplier Navetas using a 'Loop' monitoring device. The 'Loop' data provided cumulative watt-hour (Wh) readings observed at 15-minute intervals for each participating household.

Prior to analysis and the generation of customer type demand profiles, the Loop data is pre-processed to remove erroneous and interpolated consumption values[7]. The 15-minute consumption data was aggregated to 30-minute consumption totals for use in generating customer type demand and intervention impact profiles.

Census 2011 output area data

Although Census data is not used directly within the Customer Model, the construction and definition of the customer types have been aligned to match the categorisation within the Census statistics available at the Output Area (OA) scale. These OA level tables contain aggregate household counts for a range of households and household response person characteristics and are used within the Census Interface (see section 3.2.2) to determine the number of households within each customer type that are connected to any network element.[8]

3.1.2 Network Model requirements

- Customers types
- Seasons/days/ half hourly profiles
- Intervention profiles

3.1.3 Improvements in customer modelling: development of customer typology

The SAVE Customer Model has developed a customer typology using a set of household characteristics to represent some of the diversity in load profiles between households. Candidate characteristics for the typology were available from the recruitment survey conducted with households participating in the SAVE trials, however only those also available within the Census OA level statistics were used to create the typology. This compatibility ensures that demand profiles for each customer type can be allocated in the correct numbers according to their proportion within each geographic area (see below). This functionality is provided by the *Census Interface* (see Section 3.2.2).

6 R is a programming language contained within a software environment used for statistical analysis

7 For further details of the data cleaning procedures see Rushby and Harper (2018), *SAVE Loop Energy Saver Data Cleaning and Preprocessing*. SAVE Project Report, University of Southampton.

8 Available from Nomisweb (https://www.nomisweb.co.uk/census/2011/data_finder)

Out of a selection of candidate variables, the three characteristics found to best predict the variability in household consumption during peak hours were used to define the customer types: number of people, number of bedrooms and primary heat source. An iterative process was used to balance the requirements of the customer types definitions: to represent as much variability in peak-hours demand and profile shape as possible while maintaining a sample size sufficient to generate representative profiles for each type.[9] The final categorisation of customer types was found to predict 29 percent of variability in peak hours demand. Table 1 shows the customer types created for the SAVE Customer Model.

Table 1: Final customer type categories represented in the SAVE Customer Model

<table>
<tr><th></th><th></th><th colspan="4">Number of bedrooms</th></tr>
<tr><td>Heat source</td><td>Number of people</td><td>0-1</td><td>2</td><td>3</td><td>4+</td></tr>
<tr><td>Gas</td><td>1</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Gas</td><td>2</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Gas</td><td>3</td><td colspan="2">✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Gas</td><td>4+</td><td colspan="2">✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Electric</td><td>All</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Other</td><td>All</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td></tr>
</table>

3.1.4 Customer Model outputs

The Customer Model provides two outputs in the form of load profiles for each of the customer types:

1. *Baseline demand profiles:* 'baseline' profiles created from households within the control group, with no interventions applied throughout the trials;

2. *Intervention impact profiles*: profiles created from analysis of the impact of a number of energy efficiency and behavioural change interventions.

These outputs are passed from the Customer Model, via comma-separated value (.CSV) files, to the backing store of the Network Model. One file was created for each customer type and each representative case (i.e. representative days within different seasons). Prior to performing the aggregation into demand and intervention profiles, the consumption data from the SAVE sample households were initially aggregated to 30-minute time intervals using summed pairs of the 15-minute data for each household.[10] The date intervals used for the representative days within each season (i.e. each case) are given in Table 2.

Table 2: Representative days and seasons

Representative case	Season	Date range	Case description
High demand, no generation	Winter	11th to 17th December 2017	Representative high winter load
High demand, high generation	Spring	19th to 20th March 2018	Representative spring high demand – good generation
Low demand, high generation	Summer	30th July to 5th August 2018	Representative summer load with low load and high generation
High demand, low generation	Autumn	19th to 25th November 2018	Representative autumn load with high load and low generation

For the purposes of the SAVE project, the following statistics (metrics) were provided for each of the above profile types:

- Mean half-hourly consumption (kWh) for each of the 48 'half-hours in the relevant summarised period: these are taken as the ***P*** value for WinDebut;

- Standard deviation (kWh) for each of the 48 'half-hours in the relevant summarised period: these are taken as the ***Q*** value for WinDebut.

9 In order to maintain the sample size for less common customer types, some categories of the were combined, for example households with 3 or 4 persons in dwellings with 0-1 bedrooms were combined with those in 2-bedroom dwellings. For more details of the development of the customer typology refer to SDRC 2.3: *Customer Model Final Report*, available at https://save-project.co.uk/reports-and-presentations/

10 In addition, for some cases, representative days were averages across weekdays rather than single specific days of the week. In this case, demand profiles and intervention effects were evaluated as averages, summarised across a number of days to create average weekday demand for each 30-minute time-period. In these scenarios, profiles were generated for three 'day-types': *Weekdays, Saturdays and Sundays,* although only profiles generated for weekdays involved summarising data across multiple days.

Due to the small number of SAVE sample households in the 'electric' and 'other' non-gas customer type categories, synthetic demand profiles were generated for these customer types to mitigate small-sample issues. For more details on this process refer to SDRC 2.3.

Figure 2 shows examples of the baseline demand profiles generated for representative weekdays during winter for all customer types. Note that due to the collapsed customer type categories, no profiles are shown for 3 and 4+ person households with fewer than two bedrooms for gas-heated households. In Figure 3, synthetic profiles (darker lines) are shown alongside the observed mean profiles (lighter lines). Synthetic profiles are discussed in more detail in SDRC 2.3 (Customer model).

Figure 2: Example baseline demand profiles for gas-heated households, weekdays

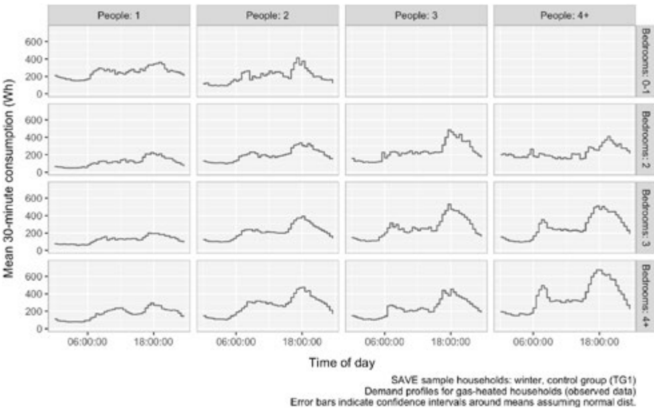
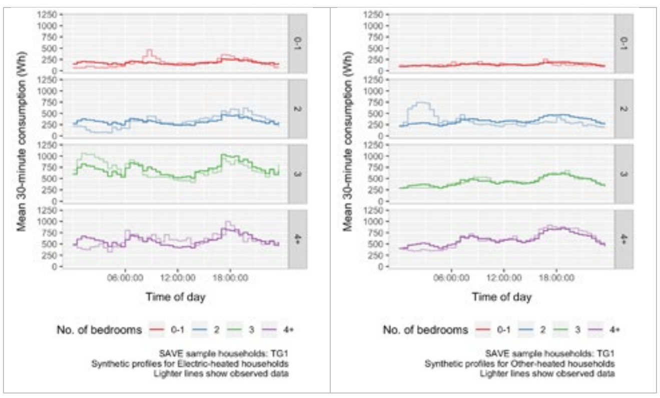


Figure 3: Example baseline demand profiles for non-gas heated households, weekdays (Electric left panel, other non-gas right panel)



Comparison of Customer Model inputs

The SAVE customer type profiles improve upon the granularity of customer representations compared to existing input load profiles. To illustrate, the SAVE profiles for gas-heated households have been compared to profiles from Energy Networks Association (ENA) Engineering Recommendation P5[11] with the results shown in Figure 4 below. The SAVE profiles (black profile in the figure) for 1-person households with 1 bedroom and 2-person households with 3 or fewer bedrooms are comparable with the 'low income' P5 profiles (blue in the figure). The profiles for one-person households generated by the SAVE data are generally lower than all of the P5 profiles. SAVE demand profiles created for 3-person households are generally comparable to the 'medium income' profiles from P5 (green). Only the profile generated for 4(+)-person and 4(+)-bedroom households is larger than the 'high income' P5 profile (red).

Figure 4: Comparison of household load profiles: SAVE gas-heated customer types and ENA P5

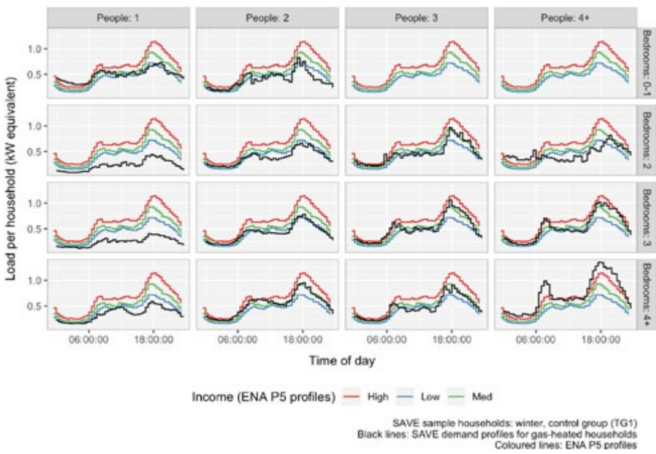
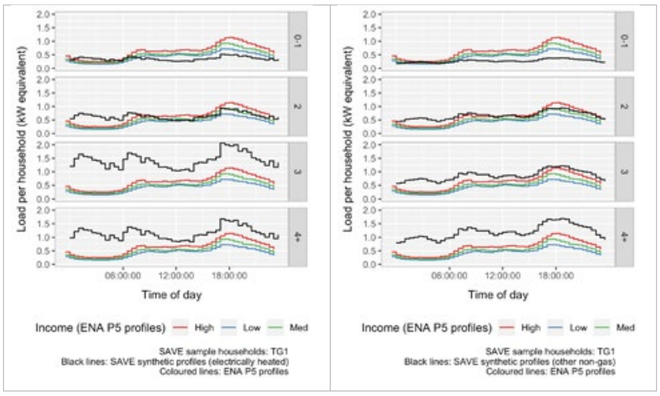


Figure 5 shows the same ENA profile data against the non-gas-heated customer type profiles.

In the left panel, it is clearly shown that the P5 profiles significant underestimate loads for households living in dwellings with three or more bedrooms compared to the SAVE electrically-heated baseline demand profiles. The P5 profiles also overestimate loads for smaller dwellings (one or fewer bedrooms). SAVE provides overnight load profiles that are more representative of households with electric storage heating (e.g. Economy 7) and show the P5 profiles are clearly underestimating demand. Comparing the P5 profiles with the SAVE other-non-gas baseline profiles (Figure 5, right panel), the SAVE profiles provide significantly more variability in demand.

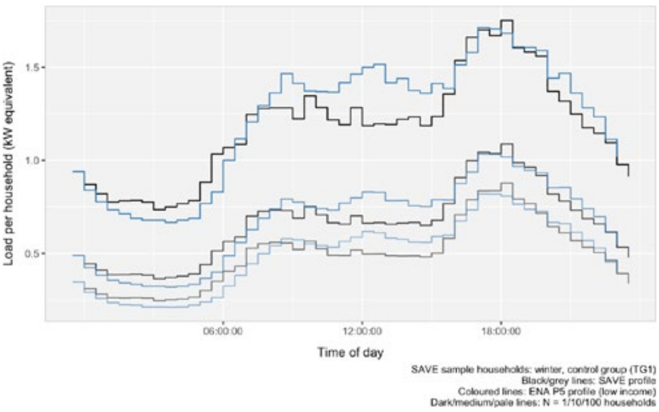
11 Energy Networks Association, *Engineering Recommendations P5: Design methods for LV underground networks for new housing developments*, Issue 6. 2017

Figure 5: Comparison of household load profiles: SAVE non-gas-heated customer types and ENA P5



The figures above show only the mean demand values compared (*P* component only). To compare WinDebut input profiles, the full loading was calculated using the ACE 49[12] methodology (including mean demand and enhancement demand components, *P* and *Q*). The results for a single customer type are shown in Figure 6 and reveal comparable loads when including the impact of standard deviation for a range of group sizes (here SAVE is represented by black/grey lines whilst the P5 profiles are represented by varying shades of blue.) Lighter colours represent a greater number of customers. This shows how the load per customer estimates fall with more customers as diversity tends to smooth out extremes in consumption. The variability in these profiles is dependent upon the standard deviation, which is incorporated in the Network Model using the *Q* value.

Figure 6: Comparison of WinDebut loads for SAVE and ENA ER P5 profiles using a single customer type, Gas 2-person, 3-bedroom for various customer count (N = 1, 10 and 100 households)



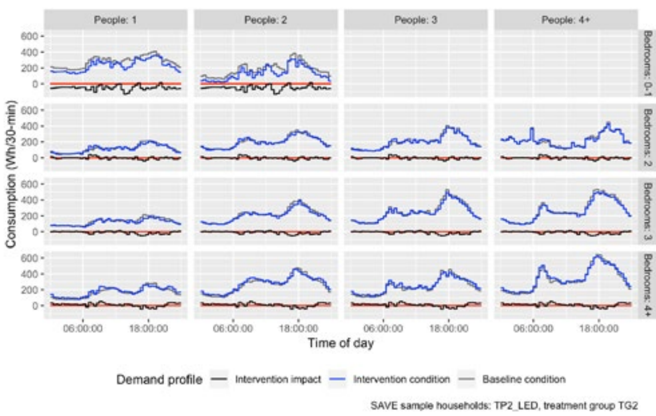
Intervention Profiles

The intervention impact profiles provide values of the change in mean half-hourly demand and standard deviation under intervention conditions for each set of representative days (seasons) and for each simulated intervention treatment.[13] Due to the high variability of estimated treatment effects caused by small sample sizes within customer types, the values for intervention impact profiles were disaggregated by only one variable (number of bedrooms) for gas-heated households, and only a single impact profile created each for electric and other non-gas-heated households.

Figure 7 below shows an example of the construction of customer type demand profiles under treatment conditions for SAVEs LED lighting intervention. In the figure, the black lines represent the 'impact' profile for the intervention (i.e. the treatment effect), grey lines show the 'baseline' (control group) demand profiles, and the blue lines show the resulting intervention group demand profile (sum of baseline + impact). The figure shows that the same intervention impact profile has been applied to all customer types of each dwelling size (number of bedrooms) category (i.e. all customer types in each row).

By combining the two outputs, the sum of *baseline* and *intervention impact*, the two outputs provide the network modeller (within the SAVE project, the Network Model) with the appropriate household demand to compare loading on the network under control and intervention conditions.[14]

Figure 7: Example of intervention load profiles (blue) constructed using baseline (grey) and intervention impact (black), LED upgrades treatment (weekdays)



12 ACE Report No. 49 (1981) Report on Statistical Method for Calculating Demands and Voltage Regulations on LV Radial Distribution Systems

13 The values for intervention effects were estimated using a difference-in-differences approach. For more details refer to SDRC 2.3: *Customer Model Final Report*, available at https://save-project.co.uk/reports-and-presentations/

14 For more details on the generation of the *baseline demand* and *intervention impact profiles* refer to SDRC 2.3: *Customer Model Final Report*, available at https://save-project.co.uk/reports-and-presentations/

Using household characteristics linked to Census data to map variability in load profiles to networks

By including a primary heat source, the customer typology provided by the Customer Model captures the diversity in demand profile shapes originating from the provision of space and water heating using different household fuels. While the profiles (and wider population) are currently dominated with gas-heated households, the customer typology allows network planners to apply demand profiles that are more representative for households heated with other fuels: electric and others such as solid and biomass fuels. The Customer Model also allows expansion of the customer typology to include additional profiles, for example, additional heating types such as ground- and air-source heat pumps, allowing network planners to simulate scenarios with differing levels of penetration of low-carbon heating technologies.[15]

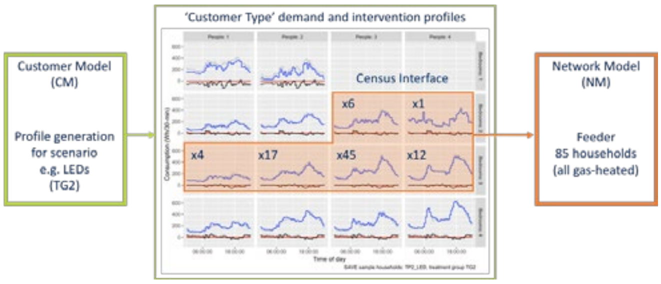
The relative numbers of each type of household represented in the model varies considerably between Census Output Areas. For example, Figure 8 shows the variation in the proportion of 1-person households across part of the SAVE study region.

Figure 8: Visualisation of Census Output Area statistics for household size, percentage of 1-person households (image source: datashine.org.uk)

Given that these characteristics are strongly associated with differences in customer load, by allocating the correct proportion of households (and linked demand profiles) by customer type to each area, the impact of the specific mix of household characteristics is reflected in the distinct loading profile for each Census Output Area. As network topologies can be mapped to Output Areas, the process extends to mapping the loads disaggregated by household characteristics to network elements defined by geography.

The process is visualised in Figure 9 below. From left to right, the figure provides an example of using Census statistics to allocate customer demand and intervention profiles to an element of the network. The Customer Model creates the load profiles for each customer type for a specified intervention: in this case an intervention using LED lighting upgrades.[16] The appropriate quantities of each customer type – and their associated profiles – are selected using the Census interface, to be applied within the Network Model. In this example only six profiles are selected (within the orange-shaded box) as the other types of customers are not connected (do not exist) in this hypothetical network.

Figure 9: Allocating customer load profiles using Census Interface



By allocating the appropriate load profiles linked to household characteristics in this way, the Customer Model and Census Interface provide the Network Model with the appropriate load profiles for the types of customers connected to each network.

15 The SAVE customer type load profiles do not currently include representative profiles for households with heat-pumps due to the small number of households.

16 Profiles for gas-heated households only are shown in the example for clarity.

3.1.5 Limitation of Customer model and potential impact on the analysis

As noted in the sections above and in more detail in SDRC 2.3, there were a number of limitations in generating demand profiles from the SAVE sample household consumption dataset. In brief, these were:

- Small sample sizes provided unrepresentative profiles for some customer types with very large variance and standard deviation values. This was particularly evident in non-gas households making up only ten percent of the SAVE sample;
- High variability and uncertainty in estimated intervention impact across customer types. The trial results did not support disaggregating intervention impacts into customer types and required collapsing the categories used to improve usability;
- Unrepresentative demand in some non-gas customer types resulted in unrepresentative scaling factors for some synthetic profiles (these are discussed in more detail in SDRC 2.3). While profile shapes were unaffected, the demand profiles created for some customer types were unexpectedly high, or low compared to adjacent types.

All of these limitations have the potential to affect the simulation of loads on network assets by providing unrepresentative baseline loads and/or estimates of treatment effect (intervention impacts). Where the estimated treatment effect is unrepresentative, an erroneously high estimated impact may lead to conclusions from the NIT that a SAVE intervention is more or less effective and provides greater or lesser load reduction than supported by the analysis performed for the trial evaluation.

It is clear from Figure 4 and Figure 5 that the SAVE data provides a more granular approach than current industry accepted profiles allowing for a more precise understanding of how different customers consume their energy, in addition to a means of scaling results across outputs areas and to the network using a census interface (section 3.2.2). Nonetheless to avoid any unrepresentative impacts of small sample effect a DNO may wish to put artificial parameters around profiles with less certainty. Whilst this is not perfect (the perfect solution would be to gather more and more data), this would be both cost and time effective and is largely accepted as common practise where information is imperfect.

3.2 LV Network Model

The Network Model takes a nodal approach to building a low voltage distribution network. This requires a DNO to understand the scale of its network in terms of transformer size, cable length and cable type (to determine capacity). Likewise since the Network Model is required to interface with the Customer Model it must understand the number of customers on each part of its network, where these customers are located geographically (to best understand the demographics of said customer, see section 3.2.2) and whether they are a domestic connection or another form of connection (commercial, street lighting etc.).

3.2.1 GIS and SIMS data

In order for a user to create a study network in the SAVE Network Model they will use both network data and customer location data. Within SSEN the former is provided through GIS (Geographic Information System) and the latter through a Supply Information Management System (SIMS).

Customer address data is extracted from SIMS for the substation(s) in question and formatted feeder-by-feeder. Customers are then plotted geographically using a 'geo-coding' tool which displays customer addresses as points (this is done through GIS software such as 'Google Earth'). This process provides spatial datasets which could be transformed into shape files and imported in GIS software (i.e. QGIS, ArcGIS) for manipulation.

Data from SSEN's GIS records of its network can then be catalogued, length of feeders calculated and built as a combination of 'branches' and 'nodes', effectively providing a trace representation of the physical distribution network. This is overlaid with the SIMS data point (customer location) to add the appropriate number of customers to each branch of the network (a feeder may be made up of a number of branches and nodes). Each customer (postcode identified) was therefore given a corresponding branch/node ID to define their location on the network. An example output from this process is shown in Figure 10 below for a substation called: Allan Way. This data could now be exported to table format and stored in the Network Model ready for assessment where it has profiles attached to it through the census interface.

Figure 10 Geospatial mapping of SIMs and GIS data

In future SSEN intends this process to be automated through its Electric Office (EO) software. EOs functions will automatically provide an understanding of where and how customers interact with the network through a geospatial representation that can be loaded directly to the Network Model.

Table 4 Census Postcode formatting

3.2.2 Census interface

In order to apply the output of the Customer Model (customer profiles, scaled by output area) to the DNO's network as represented in the Network Model (which flows within and across output areas) the project required an interface. In planning to build an appropriate interface the project looked at variables which were common between both output areas and the network mapping information discussed in section 3.2.1 above. Postcodes acted as this unique identifier.

Several stages of data formatting were required for (i) linking postcode data from the network to census areas, and then (ii) applying the appropriate profiles.

Network Approach

From a network perspective data was downloaded on each LV substation in SSEN's southern area (SEPD) providing a list of addresses (including postcode) for each customer connected to each substation and feeder. This data was compressed to show the quantity of customers in a given area residing in each postcode boundary. An example is shown in Table 3.

Table 3 Substation postcode formatting

	Postcode	Quantity of Customers
SAVE SUB 001	RG1 XXX	10
	RG1 XYY	1
	RG1 XYZ	45

Census Approach

Census areas follow postcode boundaries, however there are quite often several postcodes which may reside in one census output area. As a result, census profiles could neatly be matched with postcodes. Those postcodes could then be associated with a percentage split of customer types (CT) based on the customer types residing in their over-arching output area. An example is shown in Table 4 below.

OA	Postcodes	CT 001	CT 002	CT003	...	CT022	Total
001	RG1 XXX	40%	20%	20%	0%	20%	100%
	RG1 XYY	40%	8%	20%	0%	20%	100%
002	RG1 XYZ	0%	60%	5%	35%	0%	100%
	RG1 XXY	0%	60%	5%	35%	0%	100%
	RG1 ZZZ	0%	60%	5%	35%	0%	100%

The final step of the census interface was to link Table 3 and Table 4 and allocate customer types proportionally by the number of customers in a given postcode onto the substation in question. Where the number of customers matched perfectly with the split of customer types this can be done easily, as seen in row 2 of table 5. However, when customers did not match perfectly it is not possible to have a percentage of a customer type. Resultantly, customer types with the highest weighting were allocated to the customers. A logic was also applied to avoid potential for error within this 'rounding' approach. The logic ensured the total number of customer types allocated to a post-code matched the total number of customers on that postcode. Table 5 below shows how this process would look on the same substation displayed in Table 3.

Table 5 Substation data matched with customer types

	Postcode	Quantity of Customers	CT001	CT002	CT003	...	CT022
SAVE SUB 001	RG1 XXX	10	4	2	2	0	2
	RG1 XYY	1	1	0	0	0	0
	RG1 XYZ	45	0	27	2	16	0
	Total	**56**	**5**	**29**	**4**	**16**	**2**

This table is then used to pick up customer type profiles from the Customer Model (as shown in Figure 9) for use in the Network Model.

SSEN have completed census mapping across the whole of it's southern (SEPD) license area allowing the process of identifying customer types to be automated in Microsoft Access. Other DNOs would have to repeat this mapping exercise for their own license areas.

Whilst the census interface provides a crucial interlink between the Customer Model and Network Model its use is not limited to the NIT. By linking census information to the network, SSEN intends to leverage this cross-vector database in future to understand how other forms of demographic information may shape network loading/load growth. For instance, SSEN can use data on the number of vehicles a household owns or type of housing (flat, terraced, detached, semi-detached) to forecast where EV uptake might be most pronounced. Likewise, if a government policy change meant a certain demographic was likely to receive support in increasing the energy efficiency of their property, SSEN might be able to see how this would impact substations and whether there was merit in the DNO supporting such a scheme (i.e. through stacking funding) in certain areas of constrained network to avoid reinforcement.

3.2.3 Network Model input file format

The data required to manage the Network Model is held in two places:

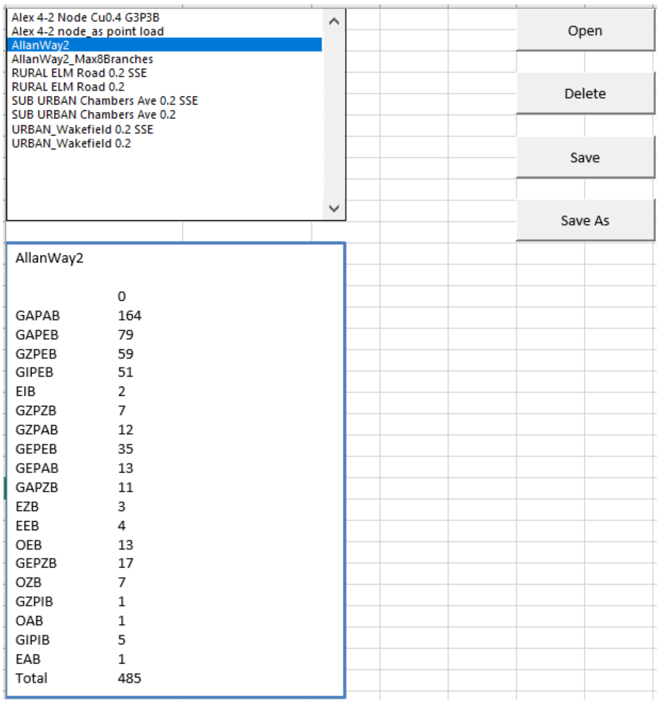
- The first store relates to templates describing the electrical infrastructure and the location of customers on the network, held as .csv files. This data is built out of the GIS and SIMS records described in section 3.2.1 and the census mapping described in section 3.2.2.
- The second store is known as the 'backing store' and holds information that includes the customer profiles. This is described in section 3.2.4.

This section describes how the data related to the electrical infrastructure and customer locations (i.e. the first store) is loaded into the NIT, after completing the mapping exercise using the census interface.

Throughout the processes defined in sections 3.2.1 and 3.2.2, users are able to load ready-made templates into the Network Model via the network build tab. For these templates to be available to the user, .csv files containing the network data and customer allocations will need to have been prepared and loaded into the templates folder. The Network Model uses a representation of the network in terms of nodes and branches, described in more detail in SDRC 7.3/8.5.

Figure 11 shows an example of how users can load templates into the Network Model. The top box within this figure shows the list of networks that are available for study. The second box lists the demographics of customer types within the network in question to be drawn on from the Customer Model[17].

Figure 11 Example of template selection tab



Users also have access to the 'Branches input' tab and the 'Load inputs' tab to either view the structure of the network and customers (or alternatively build custom models as shown in Figure 12 and Figure 13. (The data format for Figure 13 is also explained in more detail in SDRC 7.3/8.5)

Figure 12 Example of Branches input tab

Transformer Rating [kVA]	500					
Substation Node	100					
Near Node	**Far Node**	**Length (m)**	**No of Phases**	**Cable Type**	**Main / Service**	**Status**
1	11	1	TRIPLE	CONSAC 185	MAIN	ON
2	68	206	TRIPLE	CU 0.1	MAIN	ON
3	70	31	TRIPLE	CU 0.25	MAIN	ON
4	125	12	TRIPLE	WAVE 300	MAIN	ON
11	14	129	TRIPLE	CU 0.1	MAIN	ON
11	12	56	TRIPLE	CU 0.1	MAIN	ON
12	13	75	TRIPLE	CU 0.1	MAIN	ON
14	21	5	TRIPLE	CU 0.1	MAIN	ON
14	15	1	TRIPLE	WAVE 95	MAIN	ON
15	16	6	TRIPLE	WAVE 95	MAIN	ON
16	17	28	TRIPLE	CU 0.06	MAIN	ON

17 The Network Model only loads letters, as a result, letters I = 1, Z = 2, E = 3 and A = 4. For instance, GAPEB = Gas, 4 Person, 3 Bedroom.

Figure 13 Example of load input tab

							Phase Imbalance				
							Red (%)	Yellow (%)	Blue (%)		
Node	Type	No of Consumers	Consumer Type	No of Phases	Phase Sequence	Balanced	Red (%)	Yellow (%)	Blue (%)	Annual Consumption (kWh)	Status
68	BRANCH	12	GAPAB	TRIPLE	AUTO					1000	ON
70	BRANCH	3	GAPAB	TRIPLE	AUTO					1000	ON
14	BRANCH	4	GAPEB	TRIPLE	AUTO					1000	ON
13	BRANCH	2	GAPEB	TRIPLE	AUTO					1000	ON

A key feature of the load input tab, as shown in Figure 13, is the ability to allocate loads to phases to simulate a global phase imbalance target[18]. This allows users to replicate customer phase allocation on the basis of observations made at the source substation.

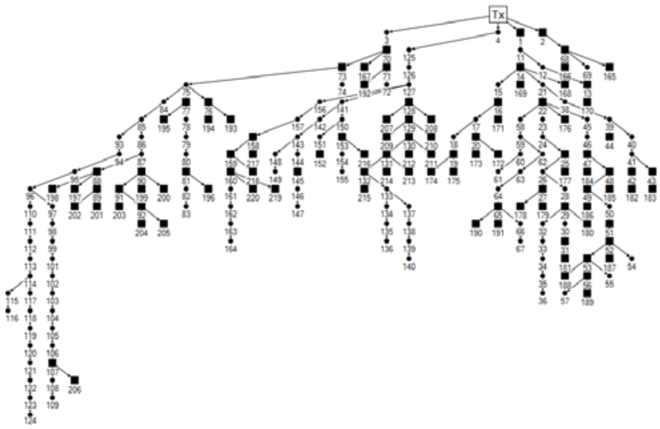
The Network Model is supported by output from the census interface (described in 3.2.2) to allocate customers to locations within the Network Model. Using information from the census interface, each customer is placed upon a node that has already been declared within the Network Model.

It should be noted that each point load entry allows the user to declare multiple, but identical, users to be connected at one node. If the user wishes to declare multiple customer types, then a new entry per customer type would need to be declared. The point load representation allows each customer to have a different customer profile. However, this requires that a node and service cable is declared for each customer type. Customers modelled as a point load can either be assigned to meet a global imbalance setting or alternatively can be assigned manually per row.

Once the network connectivity has been loaded into the Network Model, it is presented in a visual format to the user to help verify the model. An example of this is shown in Figure 14, which also shows the location of the secondary transformer.

More information on the use of the Network Model is provided in SDRC 7.3/8.5.

Figure 14 Resultant Network Topography



3.2.4 Pricing Model and Customer Model input file format

The backing store is implemented in a Microsoft Access database and it contains information to be used within the Network Model and Pricing Model.

3.2.4.1 Storage of Customer Model parameters[19]

The backing store stores parameters passed to it from the Customer Model as follows:

- The mean average power consumption, per half hour period, for each customer type, for representative days within different seasons prior to any form of energy efficiency intervention.
- The standard deviation, per half hour period, for each customer type, for representative days within different seasons prior to any form of energy efficiency intervention.
- The change in mean average power consumption, per half hour period, for each customer type, per SAVE intervention, for representative days within different seasons. These profiles are used to study the effect of SAVE interventions upon the LV network and the HV network.

18 The global imbalance setting refers to the ability of the programme to allocate customers to phases to meet an observed value of phase loading imbalance. As an example, if the difference in phase loading was measured at the feeder source, this could then be used to inform the study.

19 Ultimately this is the fixed output from the Customer Model i.e. baseline and intervention profiles for each customer type as shown in Figure 2, Figure 7 and Figure 9. If new consumption data and/or intervention data was available, it would be run through the Customer Model to provide new profiles which would then be exported to the backing store. As before the information here would be picked up by the census interface upon demand from the Network Model.

In addition to these parameters, this part of the backing store also allows for fields that can be used to manipulate parts of the Customer Model as follows:

- Erosion factors – These are factors which can be used to express a gradual decline in the effectiveness of SAVE interventions delivered by customers over time. Each customer type can be allocated an erosion factor per year to reflect how much of the turn down observed in the first year of the intervention should be expected in the subsequent 20 years.

- Growth factor weighting – This factor allows certain customer types to be desensitised to energy growth or LCT growth parameters. This weighting may be used to avoid allocating growth assumptions to customer types whose electrical consumption would not be expected to change i.e. street furniture or small commercial enterprises.

- The number of lightbulbs per customer type (LED interventions only). This parameter describes the number of lightbulbs per property for a given customer type. This parameter is used within the Pricing Model but is associated with the Customer Model.

3.2.4.2 Storage of Pricing Model parameters
To support the Pricing Model, the following parameters are stored:

- Price signal success rate per customer type – This parameter describes the expected rate that customers respond to a price signal. This parameter is used to calculate the cost of price signals and the amount of turn down that is presented in the price signal methodology.[20]

- Price signal elasticity curves per customer type – These parameters express the relationship between the payment level offered on SAVE's peak banded price signals (see SDRC 8.4/8.7) and the amount of turn down delivered by each customer type.

- Recruitment assumptions. This set of assumptions is used within the HV module only and reflects the relative uptake of customer types to deliver each of the energy efficiency interventions within an HV or EHV constraint.

- Community coaching cost assumptions – These fields support the costing of the community coaching intervention as per the methodology described in SDRC 7.3/8.5. These fields consider the fixed and variable setup costs, and also the fixed and variable ongoing costs for this intervention.

- Data led engagement cost assumptions – These fields support the costing of the data led engagement intervention as per the methodology described in SDRC 7.3/8.5. These fields consider the fixed and variable setup costs, and also the fixed and variable ongoing costs for this intervention.

- Low energy light bulb cost assumptions – These fields support the costing of the LED intervention as per the methodology described in SDRC 7.3/8.5. These fields consider the fixed and variable setup costs, the variable lightbulb costs[21], and also the fixed and variable ongoing costs for this intervention (although in testing it has been assumed the variable ongoing costs of the LED intervention is zero).

- Transformer replacement unit cost assumptions to enable costing of transformer replacement schemes.

- Cable replacement cost assumptions to enable the cost of cable installation schemes.

20 SAVE trialled both opt-in and opt-out price signals trials, this toggle allows a user to amend results as customers appetites for dynamic pricing/tariffs changes over time.
21 Determined by the number of bulbs offered as described in 13.2.4.2

3.2.4.3 Data available for HV/EHV module

To enable the running of the HV/EHV module, the backing store needs to be populated with the following information:

Feeder study

For each HV feeder associated within the area to be studied, this part of the store holds the following information:

- Network Reference Number (NRN) number[22]
- Primary substation name (using the ED3[23] reference system)
- Feeder number (using the ED3 reference system)
- Full substation name
- Total number of customers connected to the feeder
- The demographics of the customers connected to the feeder with regard to each of the SAVE customer type classifications.

Placing this information into the backing store enables a user to analyse a single HV feeder. To enable users to study wider constraints, there is a facility to group primary substations into lists that map to a bulk supply point (BSP) or grid supply point (GSP), but this is not essential.

3.2.5 Customer profiles (interventions) and future scenarios

If a given network study signals an overload, assessment is passed from the NIT's Network Model to the Pricing Model. This is performed through a linear transfer of values across excel sheets. The Pricing Model's role at this point is to assess the characteristics of the constraint identified (does it get worse over time? At what rate?) the solutions available to manage said constraint, the capacity they can give and the cost-effectiveness of each measure (including net present value, NPV, of deferring costly options). In order to carry out this assessment, the Pricing Model must understand how effective it expects SAVE interventions to be on the area in question given the types of customer in said area. SDRC 8.3 (LED's) and 8.4/8.7 (data-informed trials and price signals trails) indicate how demographics of customers may respond differently to interventions.

In the same way the Network Model uses the backing store to draw on customer baseload profiles, the Pricing Model draws on customer intervention profiles to estimate the peak load reduction that can be expected to help manage a constraint in question (this effect may also vary based on the time and duration of the constraint; for instance LED interventions are more effective on winter evenings when lighting demand is highest as opposed during summer daytime).

As discussed in 3.1.4 due to less data for intervention profiles (than baseload profiles) customer categories were collapsed for certain interventions to minimise small sample effect creating unrepresentative demand profiles. As a result, customer type profiles fed into the Network Model for interventions may represent different customer types to those fed into demographic information. Given it is only the intervention effect profile (represented by black lines in Figure 7) that are passed to the Pricing Model this mitigates in any issues in comparing collapsed intervention profiles with the original SAVE baseline profiles.

22 The NRN number is a commonly applied system which applies a 16-digit numerical coding system to distribution system from the HV feeder level down to each LV feeder. This coding system allows each LV feeder to be linked to its parent HV feeder and ultimately primary substation.

23 The ED3 reference system is employed by some DNO's to apply a nomenclature to HV apparatus and it enables a distinct naming convention for each HV feeder.

4

USING THE NIT

4.1 Overview of the NIT user interface

The preceding sections have shown how the NIT's key mechanisms (that is: the Customer Model, Network Model and Pricing Model) interlink with one another. The following section will explore how a network planner can operate these components in a single tool to test:

- LV single assessment module – To understand current loading on a chosen network. The single assessment will highlight remaining capacity on a network as well as illustrating where thermal constraints are likely to materialise. The single assessment will be of use to connection teams in assessing available capacity for new connections.

- Future assessment module – To understand how loading on a given network may change over time under a given load growth scenario. This will be useful for network planners to study when, where and why a given network is expected to break. This can feed into reinforcement planning and price control estimates.

- Multi-scenario module – To understand the best strategy to manage a given network. The multi-scenario analysis links in with the Pricing Model to assess a range of load growth scenarios and assess the best way to manage the network. This interface allows a network planner to assess the viability of cost-effective smart (SAVE) measures against traditional reinforcement.

4.2 Use of the single assessment module

The single assessment function within the Network Model allows users to review loading on a network, based on a specified season and/or type of day (typically winter weekday as the time of year network capacity is most likely to peak and when resultant SAVE interventions were run).

This assessment is suited to studying base case conditions without any network load growth.

4.2.1 Single assessment settings

To run a single assessment study a network planner is required to input a range of study options as displayed in Figure 17. Users need to set up study option, season and day (i.e. weekend, weekday) for the analysis and may influence the amount of diversity implied by the standard deviation curves per customer type by altering the diversity weighting. Once parameters have been selected the planner can run the assessment.

Figure 15: Example of single assessment input

Study Options	DAY
Season	SPRING
Day	WEEKDAY
Diversity Weighting (Default 100%)	100%
Run Assessment	
Results Summary	
Last Run	19/03/2019 10:17
Debut Input Files	C:\Users\paul.morris\Documents\SAVE\SAVE Installation 20190318\assessments\I_SINGLE_ASSESSMEN
Debut Output Files	C:\Users\paul.morris\Documents\SAVE\SAVE Installation 20190318\assessments\O_SINGLE_ASSESSME

4.2.2 Single assessment output

The Single Assessment results allow a network planner to delve into varying degrees of detail around the status of their network. The single assessment outputs include:

- An overview tab, which summarises the extent to which each feeder in the network is constrained,

- A detailed branch loading report, showing the detailed technical impacts on each branch in the network,

- A detailed voltage report, showing the detailed technical impacts at each node on the network,

- A substation loading report, showing how the loading on the transformer varies throughout the day.

Each of these outputs is described in more detail in Appendix 1, section: 7.1.1. Although this analysis is driven by the DEBUT load flow engine, the report is published in Excel, which means that users may apply conditional formatting to the results table to highlight results.

4.2.3 Application of the Single Assessment module

The single assessment tool will be useful to the following types of business function within network owners (also including IDNOs):

- **New Connections.** By using the single assessment tool, new connections designers will be able to assess whether there is sufficient capacity within the existing network for the addition of load or generation to a new location upon an LV feeder. This tool can provide these insights on the basis of the ACE49 network design standard which would not be offered by monitoring of network loading. Carrying out this process through the NIT also ensures consistency of approach and reduces the need for manual analysis for users.

- **System planning.** By using the single assessment tool to simulate the network under today's conditions LV network owners would gain insight into what issues may be prevalent along the branches and nodes of a network – either where it has not yet been possible to install monitoring equipment, or to enrich the planner's understanding about the exact nature of network stresses in cases where monitoring data is available. Based upon their findings (i.e. if an overload is signalled or minimal capacity required) such a user may then choose to run future and/or multi-scenario analysis to inform more strategic actions.

As highlighted by the 2nd bullet point above, a significant benefit of this module lies in its ability to gain insight into whether there are any problems on the network in the, currently very common, case where widespread granular monitoring is not currently available. Furthermore, the tool can help with identifying where on the LV network monitoring may best be applied to understand historic loading. It will also report on potential loading problems on the basis of a sanctioned view of the potential for exceedance of network capacity as promoted by ACE49. This is in comparison to a user seeking to interpret the risk of capacity exceedance that is implied by a set of monitored loading data, without the support of a model.

Even where granular monitoring data is available (which may be more common in the future), the single assessment will provide benefits. It is likely that this monitoring will only provide a network owner with a view of the loading on certain parts of the network, e.g. typically the first branch of a feeder coming out of a secondary substation. This would not help when identifying overloads of sections of cable further from the substation e.g. on service cables or tapered feeders.

4.3 Use of the future assessment module

The future assessment function within the Network Model allows users to review loading on a network, based on a specified season and/or type of day (typically winter weekday as the time of year network capacity is most likely to peak and when resultant SAVE interventions were run) over time. This assessment allows users to select a load growth scenario from a pre-set database[24] or defined by themselves to understand how a substations loading may change in the future.

4.3.1 Future assessment settings

Much like the single scenario, future scenarios are run after the network planner defines a series of inputs to be studied. The parameters the user is required to set include:

- Background load growth rate (i.e. growth in consumption from non-low carbon technology devices);
- Parameters relating to the set of growth assumptions around take-up of LCT including which forecast to use, technology-specific take-up rates and general rules as to where the LCT should be assumed to be connecting in the future;
- The horizon of time that the study should cover, with the maximum end date of 2060.
- In addition to analysis of the base case network, the performance of the network following any one of the following interventions can also be studied:
  - SAVE interventions (community coaching, data-led engagement, LED engagement, price signals).
  - Transformer uprating.
  - Overlaying the overloaded sections of the circuit with a higher rated construction.
  - Splitting of the feeder to create two new feeders from the original single feeder.

Interpretation of how this looks within the model is shown in Figure 16 below. It is also visible from Figure 16 that at this point the user can also choose to run one of the SAVE interventions on their network to see how this will affect future load growth. This is done by toggling the 'run type' to with intervention' or 'without intervention'. If run with intervention the Network Model will use its backing store, combined with the census interface to import appropriate intervention profiles for the customer on the said feeder.

24 Growth scenarios pre-loaded into the NIT include both BEIS and FES forecasts. Custom scenario are created by tweaking expected EV, Heat Pump (HP) or PV uptake between present day and the last year being studied.

Figure 16: Future assessment modelling choices

Load Growth Rate (%)	2.00%
LCT Load Growth Probabilities	BEIS
PV Take Up Rate	High
HP Take Up Rate	Medium
EV Take Up Rate	Low
LCT Distribution Weighting	Near to Sub
Start Year	2058
End Year	2058
Winter Peak Only?	Yes
EV Charger size (VA)	6000
HP Size (Annual Consumption kWh)	4000
PV Size (kW)	5.5
Run Type	Without Intervention
Intervention	SAVE Interventions
Select SAVE Consumer Profile	LIGHTS
Year Applied	2039

4.3.2 Future Assessment output

The output from the future assessment can be reviewed through a number of different report styles. As with single scenarios the future assessment again provides a summary table before allowing the planner to delve deeper into their analysis.

The future assessment output includes a capability to investigate the following:

- An overview tab, which summarises the extent to which each feeder in the network reaches limits and in which year under base case conditions.
- An overview tab, which summarises the network performance, with a selected intervention, and whether capacity limits will be exceeded.
- A detailed branch loading report, showing the detailed technical impacts on each branch in the network, for both conditions with and without a capacity intervention.
- A detailed voltage report, showing the detailed technical impacts at each node on the network, for both conditions with and without a capacity intervention.
- A substation loading report, showing how the loading on the transformer varies throughout the day.

Each of these outputs is described in more detail in section 7.1.2 of the Appendix.

4.3.3 Future Assessment application

This section has shown how the future assessment module can be used to screen for unacceptable voltages and branch loading. The module then uses more detailed reports to build up a picture of when a network is heading towards non-compliance and the cause of this.

This process brings value to a DSO through its capability to provide visibility of where and when network problems will occur under a suspected load growth scenario on specific networks. This allows a DSO to make more informed long-term investment decisions based on specific assumptions around certain LV substations as opposed to taking a general approach which is unlikely to match all networks. Ultimately a network planner can then better pro-actively target network management (smart or traditional) at those substations most likely to come under constraint in the medium-long term.

This section has also discussed how the future assessment module can study the technical feasibility of SAVE interventions in deferring capital investment projects. This capability would be essential if network operators were directed to take a greater stake in the delivery of energy efficiency policy as this tool would help direct efforts to where energy efficiency interventions could solve or support a technical issue.

The next section begins to discuss the multi-scenario report which is an automated technical economic assessment engine based on the network model. Alongside running multiple future scenarios at once it looks to apply the commercial considerations to network management techniques that may be applicable to manage an overload. The future assessment module discussed in this section could also be used to provide a feedback loop to the results of a multi-scenario study. As detailed in section 4.4 the multi-scenario will provide the most cost-effective interventions for multiple potential load growth scenarios. By running the suggested intervention combination through the future assessment module – because it considers a wider range of network conditions – a DNO can verify that the investment decision is still technically valid. For example, it is worthwhile checking the impact of SAVE interventions across all hours of the day, given the potential for these interventions to shift (rather than eliminate) consumption, or even vary across different seasons. This feedback loop is therefore of use to the DSO by providing confidence that the investments driven by the multi-scenario are reliable for resolving network constraints.

4.4 Use of the Multi-scenario module

The multi-scenario module of the NITs functions integrates the Network Model and Pricing Model, incorporating the outputs from the Customer Model. The functionality tests the technical and economic performance of SAVE and smart intervention against traditional reinforcement. It will carry out this assessment against a range of up to four different load growth **scenarios** which can be selected to be tested and compared. These load growths are then reported against different **strategies** for managing the network over time.

Because the economic performance of a strategy is linked to which interventions are implemented and when the Pricing Model is able to consider how the timing of different interventions changes the overall techno-economic outcome of the problem. By creating a matrix of strategies against forecasted load growth the tool gives an indication of the cost that can be incurred or avoided based on the timing of interventions, as well as highlighting the value that the flexible SAVE or smart interventions can create by deferring traditional reinforcement.

4.4.1 Multi-scenario strategies

This section explains in more detail the three strategies that have been included within the multi-scenario assessment. When the Pricing Model detects that a branch has run out of capacity it will investigate what intervention is best deployed to manage said constraint. The rules guiding the sequence of management techniques is known as an investment strategy.

Regardless of the investment strategy, the tool will always react to an overloaded branch by recommending management in the year of a new overload occurring. There are costing rules built into the Pricing Model to enable costing of each intervention, and the cost of each reinforcement is logged in the year of occurrence. For each scenario, all three investment strategies therefore, highlight not only the required interventions the years in which they are called for but also the total gross cost of each intervention and the net present value (NPV) of each strategy under each scenario.

The NIT includes three strategies:

The all-knowing investment strategy. This approach reviews the problems observed in the Network Model at the end of the planning horizon (set by the user) for a given scenario and works backwards to understand the date when the first overloads are observed on each of the LV feeders or transformer.

This strategy will then use the Network Model to identify the minimum set of assets that should be built to have sufficient capacity to last from the year of the first overload until the end of the planning horizon. If followed exactly, this strategy would therefore, minimise the number of times that interventions were required in the network (assuming that the actual patterns of load growth followed those modelled in the scenario).

This investment strategy may use traditional interventions as described in 4.4.1.1 and smart (including SAVE) interventions as described in 4.4.1.2. This strategy will allow the use of a SAVE intervention when the Network Model proves that this is capable of eliminating an overload for a period of time, and also that the cost of implementing the SAVE intervention is less than the interest earnt on deferring the capital investments for the same period of time.

The flexibility minimum strategy. This approach reviews the problems observed in the Network Model at a user nominated "network design date", which may be earlier than the end of the planning horizon (i.e. 30-40 years hence). This approach works backwards from the network design date to understand the date when the first overloads are observed on each of the LV feeders or transformer. This is similar to the all-knowing strategy, except it only considers loads up to the network design date, rather than to the end of the planning horizon.

This strategy will then use the Network Model to identify the minimum set of assets that should be built to have sufficient capacity to last from the year of the first overload until the network design date. After the network design date, the strategy will respond to overloads observed between the network design date and the end of the planning horizon by sizing physical interventions that only last for a user-specified period of growth at a time.

This investment strategy may use traditional interventions as described in 4.4.1.1 but is excluded from using smart (including SAVE) interventions as described in 4.4.1.2.

The flexibility maximum strategy. This approach reviews the problems observed in the Network Model at a user nominated "network design date" which may be earlier than the end of the planning horizon (i.e. 30-40 years hence). This approach works backwards from the network design date to understand the date when the first overloads are observed on each of the LV feeders or transformer. This is similar to the all-knowing strategy, except it only considers loads up to the network design date, rather than to the end of the planning horizon.

This strategy will then identify the minimum set of assets that should be built to have sufficient capacity to last from the year of the first overload until the network design date. After the network design date, the strategy will then respond to overloads observed between the network design date and the end of the planning horizon by sizing physical interventions that only last for a user-specified period of growth at a time.

This investment strategy may use physical traditional methods as described in 4.4.1.1 and also smart (including SAVE) interventions as described in 4.4.1.2. This approach will decide to use a SAVE intervention when the Network Model proves that there are sufficient respondents to eliminate an overload for a period of time and also that the cost of implementing the SAVE intervention is less than the interest earnt on deferring the capital investments over the same period of time.

Each of these three strategies will give a different sequence and suite of interventions (and therefore cost) associated with managing the constraints which materialise on the network, which will again vary based upon the range of load growth forecasts run. These outputs and how a planner may interpret them is discussed in section 4.4.3.

4.4.1.1 Traditional reinforcement costing

Each of the investment strategies described above can analyse the technical and economic effect of the following traditional interventions:

- **Feeder overlay:** this represents overlaying overloaded sections of the feeder with a higher rated cable. Whenever this intervention is selected by a strategy, the Network Model is temporarily altered by increasing the rating and impedance of the branch under consideration and the cost of implementing an overlay scheme is recorded in the year of implementation.

- **Transformer replacement:** this represents the replacement of existing HV/LV transformers with higher rated units. Whenever this intervention is selected by a strategy, the Network Model is temporarily altered by increasing the rating and impedance of the transformer and the cost of implementing a replacement scheme is recorded in the year of implementation.

- **Feeder split:** this represents the action of laying a new cable from the secondary substation to a point that is halfway down an existing feeder (by customer numbers). The second half of the original feeder is then directly connected onto the new cable from the source substation. The effect of this is splitting one overloaded feeder into two as a means to relieve loading problems on the original feeder.

Each of these interventions can be deployed to resolve network problems driven by customer import or export throughout the forecasted study. The approach to costing each of these interventions is described in Appendix 1 of SDRC 7.3_8.5.

4.4.1.2 SAVE interventions

The all-knowing and flexibility maximum investment strategies are able to apply these interventions if the Network Model demonstrates that they are able to defer reinforcement and they are cheaper than the interest earnt by deferring the alternative capital intervention.

- **LED lighting:** this represents the action of engaging with customers to install low energy lightbulbs as a means to avoid network capital intervention.

- **Data-informed engagement campaign:** this represents data led engagement with customers as a means to encourage beneficial patterns of consumption in order to avoid network capital intervention.

- **Price Signals:** which represents the application of price signals within the use of a DNO funded system tariff as a means to influence customers to not use electricity at times that drive reinforcement requirements.

- **Community Energy Coaching:** which represents the action of coaching local communities to act in a manner that helps defer reinforcement.

The approach to costing each of these interventions is described in Appendix 1 of SDRC 7.3_8.5[25]. Note that all of these interventions are considered to be capable of resolving network problems driven by customer import under winter import conditions only[26]. It is also assumed that the minimum scale of deployment for these interventions would be one entire secondary substation.

25 Whilst the LED intervention has a one-off Capex cost the other interventions are likely to require ongoing Opex costs to retain load-reduction.

26 SAVE trial periods ran between October and March in varying years. As a result, interventions are not applicable to dates outside these times. With more data in future these interventions could be explained across the entire year

4.4.2 Multi-scenario settings

Unlike the NIT's future-scenarios module, the multi-scenario assessment does not restrict a planner to selecting one load growth strategy. Instead, up to four scenarios can be selected within the multi-scenario to give a broad range of potential outcomes of how the energy system may change in the future. This gives a planner an understanding of the variability in the type, level, timing and cost of different interventions that could be required in the future, dependent on how the energy system evolves. The layout of an example of four scenarios can be seen in Figure 17 below.

Figure 17: Multi-scenario input screen

Start Year	2019
End Year	2060
Interest Rate	3.00%
Number of Scenarios	4
PV Size (kW - Default)	3.5
HP Size (kWh - Default)	4000
EV Charger Size (VA - Default)	3500
Network Design Year	2050
Winter Peak Only?	Yes
Intervention Period (Years)	5

Scenario		Load Growth					LCT Distribution			
Number	Name	Rate (%)	LCT Probabilities	PV Take Up	HP Take Up	EV Take Up	Weighting	PV Size	HP Size	EV Size
1	Low Growth	0.00%	Custom	Low	Low	Low	Even Distribution	3.5	4000	7000
2	Mid Growth	1.00%	Custom	Low	Low	Medium	Even Distribution	3.5	4000	7000
3	High Growth	2.00%	Custom	Low	Medium	Medium	Even Distribution	3.5	4000	7000
4	Very High Growth	3.00%	Custom	Low	Medium	High	Even Distribution	3.5	4000	7000

Much like the modules described earlier a planner will then set up a range of global parameters, this time covering both commercial factors (related to intervention costs) and network inputs. The global parameters which apply to this study are:

- The start and end years which define the beginning and end of the study.
- The investment interest rate.
- The number of scenarios to be studied, which must be an integer between 1 and 4.
- Default options for the size of PV, HP and EV. These default options will be overwritten by any assumptions made per scenario.
- The network design year, which defines a year in the future for which the initial capital invention is expected to mitigate all predicted overloads[27]. This is used within the flexibility maximum and flexibility minimum strategies.
- Whether the future of the network is to be studied under winter seasons only or all seasons.
- The number of years of future load growth for which interventions are expected to be sized after the network design year has passed. This is used within the flexibility maximum and flexibility minimum strategies only.

Each scenario can then be defined by the following parameters:

- Name, which is a user-configurable field allowing the scenario to be named.
- Load growth, which represents the growth in electrical consumption of non-LCT devices.
- LCT probabilities, which defines whether to use the BEIS defined LCT take-up rates or those specified on the custom page.
- LCT uptake rate, which prescribes which range of take-up probabilities from the LCT probabilities page is to be used i.e. low, medium or high for EV, PV and Heat Pumps.
- LCT distribution weighting, which allows users to weight where LCT technologies are connected to the LV feeder. The possible fields are: Near to the source substation, even weighting along the feeder or, far from the source substation. This allows the user to manage the uncertainty of where the LCT will be connected.
- EV size (Annual consumption in kVA), which allows the user to state one assumption for the size of the EV chargers.
- HP size (Annual consumption in kWh), which allows the user to state one assumption regarding the annual energy consumption of heat pumps that are connected into customer premises. The volume of heat pumps installed within the network is decided by the choice of LCT growth assumption and by whether the High, Medium or Low range growth assumption was selected.
- PV size (kW), which allows the user to state one assumption regarding the size of Solar PV installations.

4.4.3 Multi-scenario output

This section discusses the output from the multi-scenario analysis.

A major difficulty faced in deciding which investments to make is that the cost of any investment required will be linked to growth assumptions, yet users are unlikely to be able to reliably select which growth forecast will be the most realistic over time. For this reason, it should be recognised that using the least cost outcome to select the preferred investment strategy may not always select the least risk investment. Use of the least cost outcome to select investment choices can lead to sub-optimal investments which result in higher costs over time for customers as different scenarios materialise.

27 The network design year helps users control the number of "visits" to a feeder for mitigation that is required. A network design year in the near future reduces the risk of stranded assets until that year, but may require repeated mobilisation of projects that conduct reinforcement on different parts of a feeder afterwards.

The multi-scenario tool seeks to overcome this difficulty by enabling users to select the least risk investment on the basis of required investment across all of the potential growth scenarios. The benefit of this approach to customers is that it allows the DSO to react to uncertainty in growth forecasts and tailor investments to recognise this, instead of making significant investment choices on the basis of a single growth forecast which may not be realised.

To enable engineers to respond to the inherent uncertainty of load forecasts, the multi-scenario analysis reports the performance of **each investment strategy against each growth scenario** considered. But to enable this information to be assimilated, the information is split into a top level and lower level report.

The top-level output from the Multi-scenario process considers the investment performance of different investment strategies against the combination of growth scenarios, as shown in Section 7.2 of the Appendix. This "top level", enables users to select which investment strategy should be used on the basis of ensuring that investment regret is minimised. An example of this is shown in Figure 42 within the Appendix, which shows that the choice of different investment strategies influences the amount of investment regret that could be experienced.

The Multi-scenario report then has a lower level of the report which announces what specific interventions and actions would be required in each scenario, depending on the investment strategy that is to be followed, as shown in section 7.2 of Appendix 1. The results of this can then be considered into an investment 'watch list' for each LV network. The purpose of these 'watch lists' is to warn network operators of when they are reaching a decision point for investment and how to remain on the path of least regret (discussed in more detail in section 4.4.5).

In addition, the tool also outputs (for each strategy and each load growth scenario) the sequence of interventions and actions which has been selected by the strategy. It does this by assimilating information on the initial interventions for each strategy and scenario, and the dates they are triggered. Users are therefore offered a decision set that provides step-by-step guidance as to how they might manage their network under different strategies and different scenarios.

An example of this assimilation exercise for the 'all-knowing' strategy and how this would be used in conjunction with the future assessment, is discussed in detail in section 4.4.4.

4.4.4 Example of running the multi-scenario and future-scenario assessments

This section sets out a case study of how the NIT might be used in practice by a network planner, using an example network from SSEN's southern licence area (SEPD).

4.4.4.1 Single assessment

A planner might initially run a single assessment in order to ensure that the model has been set up correctly and that all necessary inputs have been entered appropriately. For example, the planner might first check the outputs for the Network Model for the current year, which would also confirm that the modelled behaviour of the network aligns with any existing knowledge about demand e.g. through Maximum Demand Indicators.

4.4.4.2 Multi-scenario assessment

It is anticipated that the next stage of the analysis process would be for the planner to run a multi-scenario assessment. This would identify the network interventions that could be required under all four future scenarios, including (critically) when these are needed and how much these are expected to cost.

For example, Figure 21 shows the net present value of the cost of all of the intervention installed in the case study network, Beechwood Avenue substation for low growth, mid growth, and high growth scenarios. These net present values are evaluated up to 2040. As expected, the higher the growth in the scenario, the higher the cost.

Figure 18: Net present value of scenario costs under different strategies and scenarios

It can be seen in the mid growth scenario that the "flexibility maximum" strategy provides a cost saving compared to the flexibility minimum strategy. This highlights that, in this scenario, the SAVE interventions are providing value to the network by enabling reinforcements to be deferred for long enough that the reduction in the NPV of costs (from discounting) is higher than the additional discounted from the SAVE intervention.

It can also be seen that, for the low growth scenario, the all-knowing strategy results in the lowest net present value – in this case, when load growth is low, it is more cost effective to invest once, rather than incrementally investing to address overloads. In the flexibility minimum and maximum strategies, the deployed solutions involve first installing a 750 kVA transformer and some 300mm^2 cable, before later installing a 1000 kVA transformer with 600mm^2 cable. The all-knowing strategy shows that it would be more cost effective just to install the 600mm^2 cable and 1000 kVA transformer from the start.

On the other hand, for the medium and high growth scenarios, the all-knowing strategy is actually less efficient (in NPV terms) than the flexibility minimum and flexibility maximum strategies. This is due to the effect of discount – the all-knowing strategy invests such that each feeder or transformer has the minimum number of interventions that are achievable. This means that interventions will be triggered early in the strategy but will be sized to resolve the anticipated magnitude of future overloads such that, even if the intervention/reinforcement cost is lower, the net present value is higher. Because they invest incrementally by definition, the flexibility maximum and flexibility minimum strategies will tend to involve making larger investments later, which will therefore be discounted to a greater extent when calculating net present values.

Table 6 below illustrates this, comparing the total gross cost and the NPV of the all-knowing strategy and the flexibility maximum strategy for the high growth scenario. This shows clearly that, in this case, while the total cost of the all-knowing strategy solutions is lower, the net present value of this cost is higher.

Table 6: Comparison of gross and net present value of strategy costs for high growth scenario

	Cost of high growth scenario	
	Gross cost	Net present value
All-knowing strategy	£882k	£609k
Flexibility maximum strategy	£933k	£484k

An example of the full output from the NIT presenting this information is shown in Appendix 2, chapter 7.2.

The NIT also lists the detailed interventions and actions that are required for each strategy and each scenario, as well as the actual undiscounted cost of each. An example of this full output is shown in Appendix 2, chapter 7.2. Note that this also highlights that the NIT has been run for a fourth "very high growth" scenario, but that the model has not been able to find solutions which are capable of mitigating this load growth[28]. This is flagged within the tool, prompting a planner to identify other solutions that can manage the observed load growth. It is anticipated that, at this point, the planner would run a "Future-scenario" assessment for just this scenario, in order to get a better understanding of the scale of the technical impacts.

Figure 19 summarises the cumulative non-discounted total cost associated with the flexibility maximum strategy for the low growth, medium growth, and high growth scenarios, showing how the total cost is both *higher in magnitude* and *incurred earlier* for the medium growth scenario compared to the low growth scenario, and for the high growth scenario compared to the other two.

Figure 19: Cumulative cost of flexibility maximum strategy by scenario

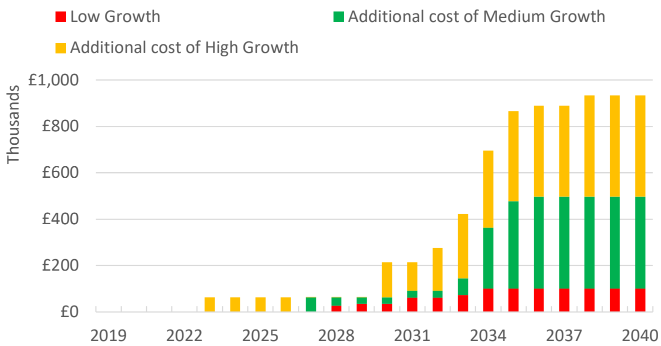


Table 7 shows which interventions would be required for the transformer and for feeder 4 of this network under the flexibility maximum strategy and the flexibility minimum strategy (note that these scenarios recommend the same interventions in the low growth and high growth scenarios), between 2023 and 2029. This highlights how the SAVE interventions are able to defer decisions about traditional interventions, but under a high growth scenario, intervention will be required either way in 2023.

28 This is indicative of a new substation being required with substantial re-modelling of existing feeders

Table 7: Overview of interventions by scenario in flexibility maximum and minimum scenarios

Year	Low growth	Medium growth		High growth
		Flexibility maximum	Flexibility minimum	
2023				Overlay Feeder 4 with 40m of WAVE 300 Upgrade transformer to 800 kVA
2024		SAVE intervention – low energy lightbulbs	Overlay Feeder 4 with 40m of WAVE 300	
2025		SAVE intervention – low energy lightbulbs		
2026		SAVE intervention – low energy lightbulbs	Upgrade transformer to 750 kVA	
2027		Overlay Feeder 4 with 40m of WAVE 300 Upgrade transformer to 750 kVA		
2028	Upgrade transformer to 750 kVA			
2029	Overlay Feeder 4 with 6m of WAVE 300			

It is envisaged that tables like these, showing the timing and nature of future interventions, would be created and regularly updated. This is described in more detail in 4.4.5. This would give a DNO information on the types of interventions they might need to be ready to make in the future, with more certainty about the exact interventions being provided as scenarios are updated and the analysis is repeated.

For example, with the lead times for LV investment typically being about one year, it is anticipated that this network would be reassessed in 2022, with up to date scenarios, to identify whether the “high growth” scenario had materialised before deciding to commission works. If a scenario of this nature had materialised, then the recommendation would be for the DNO to overlay feeder 4, and install an 800 kVA transformer. If it hadn’t, and if the out-turn scenario was more like the “low” or “medium” scenario in this case study, then this would help a planner to decide whether SAVE interventions were effective enough to defer traditional interventions until a later point.

4.4.4.3 Future scenario assessment

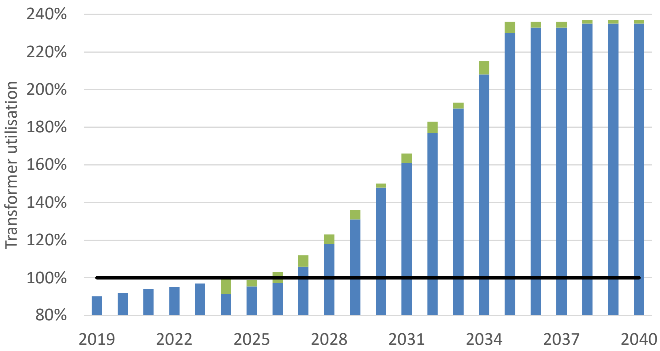
It is anticipated that where, as above, the multi-scenario assessment shows opportunities to use SAVE interventions, this would be studied in more detail by running a future-scenario assessment, with and without the intervention, for that scenario in particular.

The detailed outputs of the future scenario output, with and without a low energy light bulb intervention, are presented in Appendix 2 (Figure 44 and Figure 45), and summarised below, for the medium growth scenario. Figure 20 shows the difference in cable utilisation with and without the intervention. The total height of the bar chart (blue and green) is the utilisation without the intervention, and the green area shows the reduction in utilisation when the intervention is present. For the purposes of this assessment, it is assumed that the intervention was applied in every year, irrespective of the cost-effectiveness of this (which is a contrast to the multi-scenario assessment, which would only deploy the intervention when it is cost effective and technically effective).

It can be seen that the LED intervention consistently reduces the loading of the cable. In fact, in 2024 to 2026, this modelled reduction is significant enough to prevent the cable from being overloaded, which is one of the reasons that it is selected in the multi-scenario assessment for this scenario (the other reason is that it is found to be economically efficient to do so).

It is not shown in the figure, but the detailed outputs also show that the time of peak demand changes over the years, starting at 6pm but eventually changing to 9:30pm. This is due to electric vehicles, as the assumed profiles for EVs have their peak consumption later in the evening. This helps to explain why the SAVE interventions are proving to be less useful in the future, as they target traditional peak times which don't align with the high EV demand periods. However, information about interventions to control electric vehicle demand (e.g. smart charging) could be included within the NIT in the future, and it is possible that these might be more effective at helping to manage this high EV demand in later years.

Figure 20 Cable loading with and without intervention, from Medium Growth future scenario assessment



4.4.4.4 Future scenario transformer example

The future scenario results can help to illustrate in more detail the different decisions which are made for this scenario under each of the different strategies. This is illustrated in Figure 21 through Figure 23, showing how the timing of interventions for the secondary transformer changes with different strategies, and how the reduction in utilisation from the LED intervention (which was initially deployed to help manage the cable overload) helps to defer reinforcements in the mid-2020s[29]. (Note that Figure 20 showed the results for the cable from the future assessment, but Figure 21 through Figure 23 are visualising the outputs from the multi-scenario assessment for the secondary transformer).

Figure 21: Transformer loading and interventions from flexibility minimum strategy

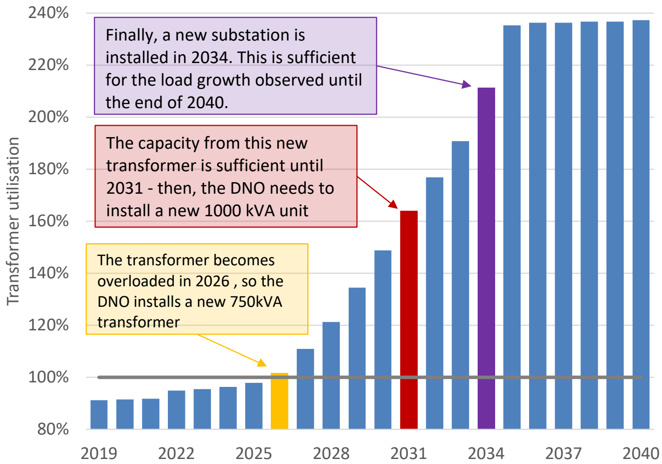


Figure 22: Transformer loading and interventions from flexibility maximum strategy

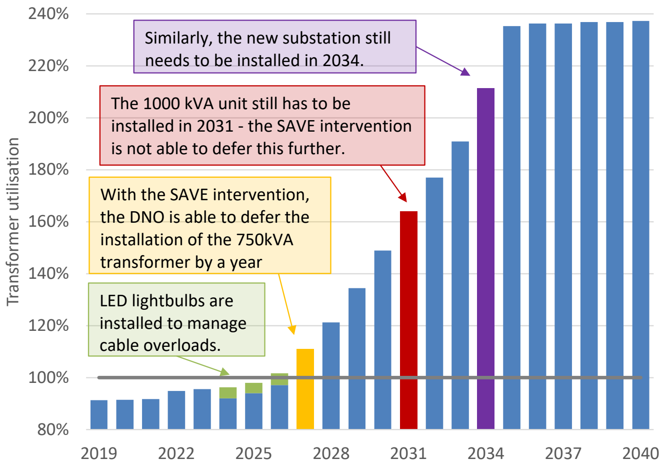
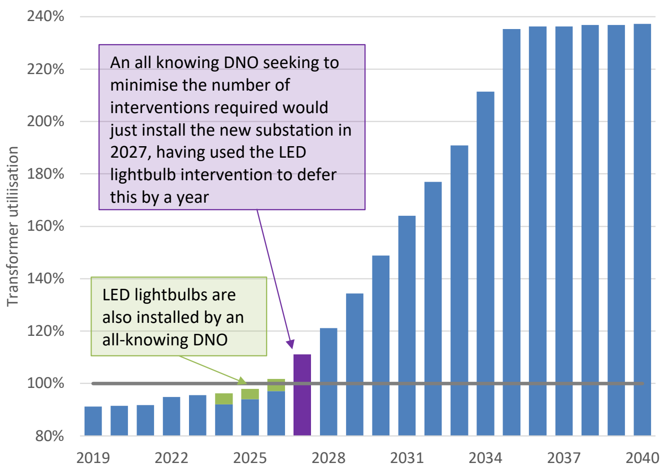


Figure 23: Transformer loading and interventions from all-knowing strategy



29 All analysis in this section is again under a medium load growth assumption.

4.4.5 Multi-scenario application

The case study shows how the multi-scenario assessment can highlight the value of SAVE (and other flexibility) interventions, where these allow investment to be deferred. By considering the differences in interventions deployed across strategies and scenarios, it can also give some initial insight into the value that deferring traditional reinforcements might have when the development of a future-scenario is so uncertain.

This could also feed directly into DSO's assessing whether a constraint management zone[30] might be a viable solution to network management (discussed in section 5.3).

Rather than running these multi-scenario analyses once, and forever committing to the investment recommendations unreservedly, it is anticipated that this would be a live process where the Network Model was updated and the rate of LCT growth was tracked and scenarios were updated. This would enable planners to have a 'watch list' of which LV feeders were approaching a trigger date for investment and what intervention should be enacted on the trigger date.

A live process of this type would result in changes to which feeders were on the 'watch list' and what the detail of the upcoming first intervention should be. By following a rolling process of this type, customers would be assured that interventions on an investment 'watch list' were the lowest cost for each given scenario.

Maintaining a live 'watch list' of LV investment plans, that is linked to assimilation tables per LV substation, would also enable a DSO to rapidly assess changes to overall budget forecasts across the licence area in response to changes to:

- economic factors such as interest rates,
- social factors such as readiness of customers to engage in energy efficiency schemes, or;
- political factors such as government support for the installation of low carbon devices.

A live 'watch list' of this nature would also enable the DSO to better engage with communities fed by a distribution substation by firstly identifying which communities are expected to be located close to LV assets appearing on intervention watch lists. Once these communities had been identified, the DSO could pro-actively target and then engage with the communities to explain the benefits of participating in energy efficiency interventions to them ready for the network need (or an SCMZ, see section 5.3). This approach could help ensure that domestic DSR network interventions were as successful as possible and maximise the social benefits of participation to customers and the wider UK.

It is also noted that whilst most LV capacity mitigations can be delivered in a short space of time, any requirements to constructing a new 11kV/LV substation can often take much longer due to the complexity of finding new land that is available and in a suitable location. The ability to cast forwards in time to work out when a new 11kV/LV substation would be justified is beneficial due to the additional lead time required to deliver projects of that nature.

4.5 Smart Interventions report

Users may use a smart intervention report to test whether the use of storage solutions can economically defer a preferred investment strategy.

4.5.1 Use of the Smart intervention report

Users may assess whether a user-supplied electricity storage installation can be used as an alternative to any of the solutions presented within the costing output.

Figure 24: Example input for Smart Interventions report

Storage Power (kW)	100
Storage Energy (kWh)	150
Duration of Peak	10
Costing Assessment Scenario	1
Strategy	All Knowing Strategy
Evaluation Year	2028
Run Assessment	

30 Constraint management zones (CMZ) are SSEN's current preferred mechanism for procuring flexibility. Whilst these are currently run exclusively on HV networks, in future DSO's may see value in evolving flexibility solutions to LV network management utilising solutions such as smart EV charging, domestic batteries and energy efficiency.

Before the commencement of this study, the user must state the assumptions for:

- The power output of one the storage unit in kW.
- The energy storage capacity of the storage unit in kWh.
- The assumed duration, in hours of the peak demand on the feeder.
- Which of the costing assessment scenarios are the basis for financial comparison, for example, this may be the low, medium, high or very high
- Which strategy is to be the basis for comparison (i.e. all-knowing, flexibility maximum, flexibility minimum)?
- The year at which the net present value of the costing evaluation results is to be assessed.

The storage feasibility report then obtains from the multi-scenario analysis:

- The cost of the preferred investment strategy
- The size and duration of the peak overload per year.

Users can then review the load flow results from the LV load flow engine to decide whether the storage assumptions can be used as an alternative reinforcement. An example of this output is shown in Figure 25.

Figure 25: Example output from storage feasibility report

Description	Price Ceiling	Feeder	First Node	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Size of Winter Peak Overload (kW)	£1,513.77	1	1	8.9	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				Yes										
Size of Winter Peak Overload (kW)	£0.00	2	2	90.1	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£0.00	3	3	0	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£0.00	4	4	0	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£0.00	5	5	0	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										
Size of Winter Peak Overload (kW)	£0.00	6	6	0	0	0	0	0	0	0	0	0	0	0
Is storage technically feasible?				No										

Each feeder connected to the substation is assessed for suitability against the storage solution through:

- Use of the price ceiling, which is the interest earnt on the counterfactual investment for that feeder. For storage to be an economic proposition, then the annual cost of the utility to obtain those services must be less than the price ceiling.
- The technical feasibility assessment which checks whether the size of the largest winter peak overload on the LV feeder is smaller in terms of energy and power than the assumed storage unit.

In the example shown in Figure 25, it can be seen that the size of the storage unit that has been assumed, can technically remove the overload on feeder 1, but not on the remaining feeders[31]. This also shows the maximum price that should be paid per year to any storage provider located on feeder 1. In the event that the assumed storage parameters were large enough to resolve overloads on the additional 5 feeders, the report would automatically calculate the price headroom for those also.

The smart interventions report is based on the output from the load flow engine instead of modelling the storage unit within the load flow model. This means that users must assume that the storage unit is always connected beneath the worst overload on the LV feeder. This is a realistic feature given that LV network analysis shows that in consumption dominated networks, the worst overloads are commonly located at the top of an LV feeder (i.e. the branches that are proximate to the source).

This report also made the limitation that the price ceiling is linked to the costs associated with a single feeder but not the upstream 11kV/LV transformer. Future development of the tool could investigate how much value a storage unit could unlock by simultaneously deferring reinforcement across multiple voltage levels.

4.6 The HV/EHV Module

The purpose of the HV/EHV module is to understand whether SAVE based interventions can provide a technical and economically feasible alternative to capital reinforcement of the HV or EHV system.

For the purpose of the SAVE project, the functionality of this module has been limited to dealing with network problems that are thermal loading problems under winter peak import conditions that can be resolved to a radial simplification. For the purpose of this report, the term "constraint" is intended to describe a collection of substations which all contribute to a forecasted overload on the 11 kV, 33 kV or 132 kV network.

This decision was made as including an HV/EHV load flow engine into the HV/EHV module was beyond the scope and purpose of the SAVE project.

31 This is indicated by the "is storage technically feasible" flag for each feeder. If the size of the nominated storage unit has sufficient energy storage and power output to remove the overload, then this flag will be set to "yes" indicating that the storage unit large enough to meet the requirement.

This module assumes that the HV or EHV planning engineer has already determined:

- The firm capacity of the constraint and the forecast peak load to be supplied in future years. For the purpose of this report, the term headroom deficit implies the difference between the firm capacity and the forecast maximum power demand.
- The cheapest network led intervention that can resolve the constraint

Before conducting this assessment, it is a pre-requisite that the census interface and customer information has been loaded into the backing store.

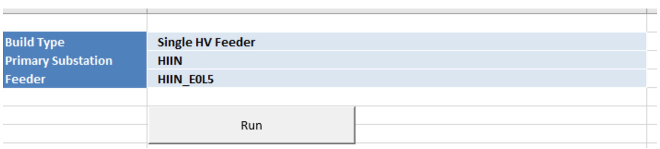
4.6.1 USE of the HV/EHV Model Network analysis

Users can apply the information from within the census interface discussed in 3.2.4.3 by either specifying that the calculation should assess one single HV feeder or alternatively that a constraint comprising of many primary substations should be analysed.

The nomination of the single HV feeder or a named constraint takes place on the assessment runner tab as shown in Figure 26. The build type allows either a "single HV feeder" or a "constraint" to be selected.

If "single HV feeder" is selected, then the user must specify a primary substation associated with the feeder before running the study. This will result in the module using the census data for the single HV feeder within the analysis.

Figure 26: Selection of constraint for study



If build type "constraint" is selected, then the user will need to nominate a constraint group that has already been declared via the constraint builder page as depicted in Figure 27.

Figure 27: Constraint builder page

The constraint builder allows users to define a new constraint, by either selecting each primary substation or BSP/GSP substation as loaded into the backing store. As discussed in section 3.2.4, the output from the Census model is loaded into the backing store which links the absolute number of customers and demographics of customer types of 11 kV feeders and also Primary substations. The action of setting the selection field next to a primary substation or BSP from "No" to "Yes" adds the substation in question to the list of selected primary substations. In the case of the BSP selection, it will add all primary substations mapped to the BSP to that list.

Once the user is satisfied with the list of selected primary substations to be included within the constraint, it may be saved for use. Prior to saving the constraint, the user must name the constraint and give a brief description of the network that it represents, for example, "Brook Street 33/11 kV substation".

4.6.2 Network headroom and growth

The previous section explains how customers may be mapped to a network constraint. This section explains how the user enters data regarding the amount of capacity in the network and expected load growth associated with a constraint. This part of the process is intended to use the output from the capacity analysis undertaken as part of business as usual network planning operations.

An example of the user interface for this part of the process is shown in Figure 28.

Figure 28: HV/EHV study input screen

Start Year	2019
End Year	2031
Interest Rate	5.00%
Growth Assumption	0.25%
Demand Response Diversity	1.0

Save Cancel

Existing N-1 Capacity (MVA)	1.1									
	Year 0 (MW)	Year +1 (MW)	Year +2 (MW)	Year +3 (MW)	Year +4 (MW)	Year +5 (MW)	Year +6 (MW)	Year +7 (MW)	Year +8 (MW)	Year +9 (MW)
Forecast	2	2.3	2.3	2.3	2.3	2.36	2.3	2.3	2.3	2.3
P2/6 contribution from DG (MW)	0	0	0	0	0	0	0	0	0	0
Capacity headroom (MVA)	-0.9	-1.2	-1.2	-1.2	-1.2	-1.3	-1.2	-1.2	-1.2	-1.2
Time of Peak	17:30									

Reinforcement scheme name	11 kV overlay									
Summary of scheme	Reinforce 11 kV feeder by laying a total of 2kM of 11 kV cable									
Year	Year 0	Year +1	Year +2	Year +3	Year +4	Year +5	Year +6	Year +7	Year +8	Year +9
Reinforcement Spend	£300,000.00	£700,000.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00
New N-1 Capacity	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
10 year NPV	£995,764.95									

This description is made in terms of:

- The start year and end year, which defines the span of the study, which in the case of Figure 35 runs from 2019 to 2031.
- A linear growth rate expressing the background load growth applicable for the years beyond the 10-year manual forecast. The growth in years 0 to 10 should be included within the load forecast. In the case of Figure 28, the assumed figure is 0.25%.
- The expected contribution to security from embedded generation. In the case of Figure 28, there is no contribution from the embedded generation considered. The decision to use this field would be informed by the F factor[32] process prescribed by engineering recommendation to account for the contribution to security from embedded generation.
- A diversity factor which reflects the aggregate difference in how different customers deliver any SAVE interventions.
- The expected annual peak electrical demand for the next 10 years for the existing network. This is entered manually by the user on the basis of known new connections and general expectation in the background load growth. In the case of Figure 4, the peak demand has been assumed to be 2MW in the first year of the study rising to 2.36MW over the intervening years.
- The residual headroom per year is also listed automatically, this is the difference between the peak demand and the P2/6 firm capacity. In the case of Figure 28, it can be seen how a capacity deficit grows from 0.9MW to 1.3 MW over the years of the study.
- The increase in capacity headroom created by the cheapest reinforcement scheme[33]. This is entered manually by the user. In the case of Figure 28, it has been assumed that the investment being tested reinforces the existing feeder to secure 3MW of demand.
- The cost of creating the new capacity headroom. This is entered manually as a time series of investments by the user. In the case of Figure 28, it has been assumed in this case study that there is a one million pound capital investment spread over the first two years of the study.

This section has described how to set up a study to enable an analysis of whether energy efficiency options may be an alternative strategy for capital reinforcement.

4.6.3 Technical and Financial comparison of interventions

Once the constraint has been defined and the headroom and growth forecasts have been loaded into the interface users may then initiate the assessment of whether domestic customers can help manage the constraint. As already discussed in section 3.2.4, this process is also dependant on assumptions loaded into the backing store that describe cost assumptions for demand response (SAVE) solutions and also customer demographic details.

The assessment runner tab launches the analysis of the interventions and reports the technical feasibility as well as the expected cost for each intervention, an example of which can be seen in Figure 29 (this figure extends 20 years into the future but only the first 8 years of the study have been shown).

32 The F Factor process is used in business as usual planning operations to take account of the statistically likely contribution to security from embedded generation.

33 This will be analysed by planners under existing procedures and hence uses the output of existing business processes to define the headroom that traditional intervention would give.

Figure 29 shows that within the constraint studied, there are 24.9 thousand customers, and that based on the customer demographics in this area and the loading required this illustration shows:

- Use of data-informed engagement and community coaching does not create sufficient turn down to resolve the headroom deficit, even in year 0 of the study.
- The use of price signals can develop enough customer response to defer the headroom deficit by 10 years. It is also notable that to achieve a 10-year deferment, the tariff would have to rise over time to reflect the fact that the headroom deficit worsened over time[34].
- The use of low energy light bulbs can defer the capital intervention for the first year of the study only.

To enable the user to decide which strategies are viable, Figure 30 reports the total net present worth of the purely capital delivery strategy (i.e. traditional reinforcement) and then the cost of the capital delivery strategy deferred by each of the feasible energy efficiency strategies. It can be seen that in this particular case, which represents a large upfront capital reinforcement, the strategy of using low energy lightbulbs to defer this reinforcement by seven years is cheaper than committing to the capital reinforcement. Users can decide which approach to take by reviewing the results of this report to decide which strategy is the cheapest.

Figure 29: HV/EHV comparison of intervention table

Build Type	Primary System								
Constraint	Bulk Supply Point 132/33 kV								
		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
	Headroom Deficit (kW) (Calculation)	-900	-1200	-1200	-1200	-1200	-1260	-1700	-1900
	Total Customers within Constraint (Aggregation)	24936	24936	24936	24936	24936	24936	24936	24936
CMZ/Price Signal	Maximum Turndown (kW) Available	20000	20000	20000	20000	20000	20000	20000	20000
	Required Tariff	0.10	0.14	0.14	0.14	0.14	0.16	0.47	0.65
	Cost of Tariff	£1,296,000.00	£1,728,000.00	£1,728,000.00	£1,728,000.00	£1,728,000.00	£189,600.00	£5,640,000.00	£7,800,000.00
Low Energy Light Bulbs	Total Feasible Turndown (kW)	1740	1740	1740	1740	1740	1740	1740	1740
	Minimum Recruitment Target (Number of Customers)	18057	24632	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible
	Cost to Procure	£55,696	£0	£0	£0	£0	£0	£0	£0
Community Coaching	Total Feasible Turndown (kW)	448	448	448	448	448	448	448	448
	Minimum Recruitment Target (Number of Customers)	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible
	Cost to Procure	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible
Data Led Engagement	Total Feasible Turndown (kW)	448	448	448	448	448	448	448	448
	Minimum Recruitment Target (Number of Customers)	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible
	Cost to Procure	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible	Not feasible

Figure 30: Financial overview of HV/EHV solutions

	Investment Requirements								
	NPV	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Cost of Capital Reinforcement	£935,650.89	£300,000.00	£700,000.00	£0.00	£0.00	£0.00	£0.00	£0.00	£0.00
Cost of Strategy Deferred by Price Signal	£17,412,528.07	£1,296,000.00	£1,728,000.00	£1,728,000.00	£1,728,000.00	£1,728,000.00	£189,600.00	£5,640,000.00	£7,800,000.00
Cost to Procure Low Energy Light Bulbs	£953,218.16	£55,696.00	£300,000.00	£700,000.00	£0.00	£0.00	£0.00	£0.00	£0.00
Cost to Procure Community Coaching	-	-	-	-	-	-	-	-	-
Cost to Procure Data Led Engagement	-	-	-	-	-	-	-	-	-

34 The NIT models SAVE's dynamic pricing trials which were designed as a DNO led incentive only mechanism (outside of DUoS). If of course such a price signal was passed through DUoS, customers may ensue/risk losses as well as benefits based on their behavioural patterns/changes. In such a world this solution is more likely to be cost-effective for the DNO, however would require consideration around supplier appetite to pass signals, customer recruitment/engagement and societal impact on (vulnerable) customers. For more details see SDRC 8.4/8.7- data informed engagement and price signals.

4.6.4 Application of the HV/EHV module

The features of the HV/EHV module allow users to review a known capacity limitation on the network and investigate the technical and economic feasibility of alternative solutions.

For example, the feasibility of price signals can be investigated by comparing the price signal report to the calculation of the annual interest earnt on a capital intervention scheme that would be required to resolve the constraint.

Alternatively, this tool could be used to conduct due diligence in constraint managed zone (CMZ): 1) before issuing a CMZ to understand whether domestic demand side response (such as the SAVE intervention) is likely to be a viable solution in managing the network and hence where the DNO may wish to target its marketing of CMZ's; and, 2) in investigating CMZ tender responses to understand whether the assumptions used around potential network management solutions are realistic in managing the identified constraint.

This tool creates value for the DSO and society at large as it will signpost which constraints can be managed by domestic demand side response measures. Given the learning from early CMZ trials which demonstrated that the success of striking an acceptable tender with commercial flexibility partners can be very location specific, then enabling visibility of viable domestic CMZ propositions will increase the number of opportunities where major reinforcements can be deferred and the value passed to society.

5

CONCLUSIONS

Section 1.1 of this report started by framing the evolution of DNO's to DSO's. Ofgem's 'Upgrading our energy system' plan published in July 2017 highlights that successfully achieve this transition to DSO requires DNO's to be "more active in managing their networks as a system—implementing innovative techniques and exploring market-based solutions as alternatives to network reinforcement". The modules within the Network Investment Tool provide a three-step process to support DNO's in this transition, and crucially, centralise all of this functionality within a single tool. The key benefits that the NIT can provide to a network planner are:

- granular **visibility** of the specific parts of LV networks that are under stress, helping to inform the need for interventions.
- the tools to assess the **viability** of smart or 'market-based' solutions.
- insights into the **commercial value** of smart interventions, particularly the value of deferring reinforcements due to demand side response interventions, and how this value may vary depending on future changes in the energy system.

5.1 Value of each model and improvement into the existing process

Three models: Customer, Network and Pricing have been explored in this SDRC. The Customer and Networks Models are linked via a census interface for translating customer demographics to the network. All three models are integrated in a DSO ready Network Investment Tool (NIT). The value of this NIT, and the value of the studies each module within the NIT can run, is summarised in sections 5.2 and 5.3 below. Each model/interface may however also provide value to a DNO when used in isolation, either as input to their own suite of tools or as a stand-alone piece of software.

Customer Model
The Customer Model methodology and outputs could be applied across industry models as an input for customer baselining and intervention profiling. Additionally, as Figure 4 and Figure 5 have shown the granular data set provided by the SAVE methodology could be used to support and add precision to ENA P5 profiles amongst other industry modelled load-profiles.

In future the Customer Model could be expanded with future study data, or smart meter data linked to demographic information when this becomes available. A full summary of the Customer Model is given in SDRC 2.3.

Census Interface
The census interface developed in SAVE could be used to match any set of census-based demographics to a DNO's network. As research starts to show links between variables of interest to the network (i.e. EV adoption, or the presence and locations of fuel poor customers) and demographic information; DNO's could use this census interface on their own networks to improve granular forecasting, which would significantly help to make intervention decisions more targeted and efficient.

Network Model
The Network Model in isolation provides a DSO with the capability to build LV models on an automated and standardised basis. When supported by the Customer Model a user can study multiple future scenarios for LCT uptake within the Network Model. This allows a DNO to predict how much of their LV network could fall outside of voltage and thermal compliance requirements in the future.

This model is based upon the methodology in the ACE49 report[35], which is used extensively by the DNOs. This means it automatically provides a representation of diversity, designing the network to the 90th percentile value of demand (i.e. to be sufficient to accommodate 9/10 diversity events). This means that when the Network Model is considering the effect of future growth and the adequacy of future capacity interventions it still remains consistent with this common approach to planning for LV demand.

Pricing Model
The Pricing Model in isolation provides a framework for identifying and assessing the most techno-economically efficient interventions for managing a given network, under a range of future scenarios. DNO's with existing network models could adopt the Pricing Model in its raw format as a series of Excel sheets and integrate it into their own existing network analysis tools. Alternatively, they could adopt the methodology behind it to fit to their own network investment tools. This could help ensure a DNO understands what actions it may needs to take to manage its networks depending on how the system develops.

35 ACE Report 49 for the design of low voltage (LV) radial distribution networks

5.2 Current network planning – BaU implementation, benefits, limitations and challenges

The report has summarised the three main modules within the NIT that a DSO would be expected to interact with in order to supplement and potentially replace existing network planning procedures. These are the single-scenario, future-scenario and multi-scenario modules.

Single-scenario
Using SAVE baseline load-profiles from the Customer Model on a network gives a user a snapshot of estimated current loading/voltage on a that substation and along its feeders. It is anticipated that this function is most likely to be used by network planners when assessing the potential for new connections. As this module also provides an illustration of loading across a 24-hour time period and can be run for each season, it may allow for connections teams to make more informed decisions about where capacity can be accommodated at certain times of day/across the year to better optimise existing assets.

The NIT completes this process with a single, easy to use piece of software, with key calculations completed automatically. It would also help DNOs to manage the assumptions that are made by planners when undertaking designs, by potentially hardcoding these into the tool. Therefore, a DNO can ensure their calculations are consistent and clear. This may be even more important when considering the role of independent connections providers – the consistency in approach and assumptions that the NIT provides will help to ensure that all external connections providers are treated fairly.

In order to understand how accurately the SAVE profiles translate to wider DNO regions[36] it is recommended each DNO tests this functionality across its regions on substations where monitoring has been applied. This will allow a DNO to anticipate any margins of error in the model and if appropriate provide adjustments[37]. As the tool is based the ACE49 method, which designs networks to the 90th value of demand after accounting for diversity, this might best be done by testing substations with several years of historic monitoring data so the predictions of the tool could be reliability compared with the monitored values.

Future-Scenario
Using SAVE baseline (and potentially intervention) profiles from the Customer Model, combined with scenario estimates (e.g. BEIS, FES or custom) allows a user to see how load growth will impact a given network over some defined time horizon. This provides visibility of under- and overvoltage across the assessed period and the scale of any cable and transformer overload. Some of this information could be gathered through other means, but the key benefit of the NIT is that it provides a very detailed and granular view about exactly where on a given network these issues may arise. This function is most likely to be used by network planners to predict and prioritise where best to target network management interventions[38].

Carrying out this analyse across substations will also allow network planners to better understand their expected capital expenditure on a year-by-year basis improving financial forecasting for future price controls.

As with the single assessment in order to understand how accurately the SAVE profiles translate to wider DNO regions, it is recommended each DNO tests this functionality across its regions on substations where monitoring has been applied.

Multi-scenario
The multi-scenario allows a user to understand the most cost-effective interventions for addressing a series of potential future energy scenarios, and how these change depending on the strategy that the DNO adopts. This module uses the SAVE baseline and intervention profiles from the Customer Model and combines these with up to four scenario estimates (BEIS, FES or custom) as well as cost inputs for different network management interventions. This module runs three differentiated strategies for managing each assumed network scenario (varying levels of load growth) in order to identify how the optimal solution to managing the network would change. Critically, the multi-scenario assessment identifies cases where smart options (particularly flexible SAVE solutions) are both economically and technically viable solutions to managing network issues. For each strategy and each scenario, a step-by-step (or intervention-by-intervention) guide to managing a constraint is provided.

36 Given they were modelled on customers from the Solent which may not be representative of the wider UK.

37 Simple means for achieving this might include applying scaling factor to all profiles or using other methods to produce synthetic profile. Ideally, this would be achieved by building on the customer model with more (and local) data.

38 Whilst this can also show impact of a certain smart intervention, considering the cost effectiveness of these intervention is best studied within the multi-scenario module, as it can provide a fuller picture of all interventions across different scenarios, supported by economic analysis. The future-scenario smart intervention is best used as a feedback loop once a smart solution has been identified by the multi-scenario, to analyse any potential knock-on effects (i.e. rebound effect) of interventions, or to gain a deeper understanding of exactly how the future scenario is affecting the network..

The assessment of smart solutions within this process provides new functionality to planning departments during the transition to a DSO (discussed in section 5.3 below). For SSEN specifically, this is likely to provide useful analysis when considering opportunities for constrained managed zones (CMZs) or other socially beneficial demand side response initiatives (i.e. through SCMZ's). The envisaged usage of the Pricing Model includes the preparation and ongoing maintenance of 'watch-lists' identifying the specific interventions that might be required under different future scenarios, where these are needed, and how much they will cost.

5.3 Future network operation

In July 2018 the Energy Networks Association (ENA) wrote a letter to the Secretary of State, Greg Clark, noting that: "DNOs commit – with immediate effect – to openly test the market to compare relevant reinforcement and market flexibility solutions for all new projects of any significant value."

SSEN's current preferred means of procuring flexibility is through a CMZ[39]. The CMZ looks to the market to provide a required level of flexibility (MW and MWh) across a pre-set availability window. Third parties providing solutions are incentivised based upon availability and utilisation payments, and flexibility providers will tender competitively to provide the flexibility services to the DNO. A price ceiling on payment amount is indicated by the NPV of deferring traditional reinforcement for the duration of a CMZ service (typically 4 years).

The multi-scenario analysis described above provides a transferable and consistent mechanism for planning teams to meet this commitment to the Secretary of State, by providing planners with:

- greater understanding as to how LCT uptake on their networks may affect loading over time; and,
- insight as to whether smart and flexible interventions are likely to be cost-effective in any future scenarios, achieved through techno-economic analysis of smart and flexible alongside traditional interventions.

A DSO ready planning department can use the NIT to assess **whether the DSO should be looking to the market for flexibility solutions** as a potentially cost-effective alternative to traditional reinforcement or not (based upon any smart and flexible solutions being identified as viable solutions within the NIT).

Such sites could then be added to a DSO's CMZ portfolio for competitive tender. Once tenders are submitted, the NIT's outputs can help a DSO assess whether said solution is likely to provide the security of supply the network requires. It is envisaged that over time, returns from tenders will help DSOs to improve how smart and flexible interventions are represented in the NIT.

For example, the NIT may predict that on a given site a DSO could expect 1 MW of load-reduction to be achieved through installation of LED's (on a given subset of customers across a constraint). However, a flexibility tender response may offer 2 MW of load-reduction, achieved through installation of LED's. This should act as a signal to the DSO that they may wish to further analyse the assumptions behind this offer to see how said tender is hoping to achieve greater load reduction than indicated from SAVE. This will help ensure the network received the level of flexibility that has been procured to manage a constraint.

In principle, the deferral of reinforcement through flexible solutions and CMZs could create even more value (than the NPV currently used to evaluate a CMZ's value) if they allow DNOs to defer expensive decisions that they may have to make in the face of significant uncertainty – this is sometimes referred to as optionality value. However, there is not yet an agreed mechanism across all DNO's for calculating the value that optionality could provide, and this value is not recognised in current regulation.

SSEN recommends that industry should account the optionality value that may be achieved by deferring large capital investment (i.e. traditional reinforcement) in uncertain situations. Running multiple intervention strategies across a range of scenarios gives a DNO insight into the different interventions which varying future scenarios might require, which might give some initial qualitative indications about the optionality value associated with different interventions. Direct consideration of this could be included within future developments of the NIT.

Section 4.4.3 explains how a user should view the production of multi-scenario outputs as a 'live' process that should be updated regularly to reflect changes in possible LCT growth. Adopting this process would enable planners to develop a 'watch list' of likely future interventions. This watch-list could be integrated with wider geo-spatial statistics (i.e. penetration of vulnerable customers as discussed in SDRC 8.3, LED trials) to support and stack the benefits case for a DNO pro-actively engaging with said communities to understand the appetite for SAVE type interventions.

39 Other DNOs are pursuing similar approaches to flexibility tenders.

The functionality which the NIT provides a network planning department is generally well orientated to aligning network planning activities with wider social benefits and government targets (i.e. engaging vulnerable customers, providing routes to market for energy efficiency, and addressing carbon reductions). The NIT and its ability to consider flexibility interventions could support DSO's wishing to deploy Social Constraint Managed Zones (SCMZ's). The SCMZ is SSEN's evolution of CMZ's which aims to open flexibility market procurement to SMEs and local organisations. SCMZ's look to achieve this through: visibility of flexibility markets, open procurement mechanisms, tender application support processes and weighting social factors within to tender assessment. Preliminary engagement in a community could stimulate the market to support SCMZ tendering when required, creating a more competitive and hence cost-effective flexibility market.

5.4 Future development

Beyond SAVE, SSEN recognises that the NIT could continue to grow and evolve to provide added value to DSOs in aspects which are outside the scope of SAVE. In section 3.1.5 some of the limitations around data feeding into the Customer Model were noted. Whilst the SAVE data-set provides a huge archive of customer load-profiles, the project acknowledges there is always room to improve this. In particular, this could include representation of new forms of intervention to run through the NIT (such as EV smart charging) or adding weighting to some of the more 'niche' customer types, specifically electrically and 'other' heated households.

Furthermore, since SAVE trials were only run over the months from October-March[40], interventions with data on year-round effects could again supplement the model's database, which might, for example, help to understand the potential for interventions which can help integrate solar PV on LV networks. A DNO may also wish to test how generalisable 'Solent' load-profiles gathered on SAVE are to their license area, with opportunities to improve the model by collecting data through their own local studies of varying customer demographic consumption profiles.

When running the model's load growth scenarios, DNOs may wish to assess more locational specific uptake of LCT's. For instance, electric vehicles could be expected to grow fastest in areas where households are already characterised as having high car ownership or where dwellings are detached/ semi-detached, as EV charge points are currently more challenging to install for residents of flats or terraced houses. This may mean integrating additional scenario disaggregation models within the NIT in order to produce more accurate and specific projections of future loading.

The NIT embeds the load-flow engines from Windebut, which assures that all analysis is aligned with the methodology within ACE 49. The SAVE project team, however, note that Windebut as a software package is somewhat dated with limited flexibility to evolve and incorporate new functionality. Likewise, it is not uniformly used across all DNO's. As a result, if developing more functionality from the tool in future we would recommend lifting the NIT 'wrapper' and applying the calculations and learning from the NIT onto a DNO's own choice of load-flow engine. Within SAVE, project partners EA Technology have highlighted that their development of DEBUT 2 could be one such tool that could provide a direct switch of engine with additional DSO ready capabilities.

In the Future DNO's may wish to build some sort of quantified "social" metric into the NIT's pricing model in order to enable SSEN's innovation of SCMZ's (which specifically account for social benefits in flexibility tenders) alongside increased drivers on social responsibility from Ofgem. The Pricing Model already contains a vulnerability layer to identify and, if necessary, remove vulnerable customer from less desirable interventions (i.e. price signals with potential for loss for those who don't shift). An inbuilt carbon calculator, or a calculator which records a monetary benefit when an intervention supports fuel poor households, within the Pricing Model (and the multi-scenario analysis which it facilitates) could help DSO's reach a more socially optimal market outcome in managing constraints and procuring flexibility. This would require further research in order to facilitate comparison of social benefits with monetary benefits for the DSO.

Finally, the NIT outputs could be integrated with wider data sources. The report has already touched upon how this may be done internally, for instance, with fuel poor or PSR household data in section 5.3. This may also be useful information to discuss with external stakeholders to understand shared agendas, opportunities and challenges. Having a clearly defined and structured 'watch-list' of potentially at-risk areas of the LV network, as previously discussed, will facilitate greater transparency of future-planning that could be shared with stakeholders to feed their own strategies.

40 Most UK networks will peak in winter months due to heating/lighting requirements and limited air conditioning penetration in domestic properties which is often associated with peak demand in warmer climates.

6

REFERENCES

David Smith, July 2018, *DNO Commitment to Openly Test the Market to Compare Reinforcement and Market Flexibility Solutions for New Project*, ENA

Ofgem, July 2017, *Upgrading Our Energy System Smart Systems and Flexibility Plan*

SSEN, 2014, *SAVE Project Bid Document*

7

APPENDIX
CASE STUDIES AND SCREENSHOTS

7.1.1 Single assessment

Following a run on the single assessment, the initial tab a user will be taken to provides an overview report (Figure 28).

This tab provides:

- The maximum transformer utilisation within the day including the number of hours the transformer is outside its rating (based on DEBUT rather than EGD analysis).
- For each feeder, the maximum feeder voltage drop, based on DEBUT rather than EGD analysis (i.e. the load flow engine add-on to DEBUT for embedded generation).
- For each feeder, the number of critical customers i.e. customers criticality who are receiving voltages outside of tolerance, with these divided into different grades of criticality which depend on the magnitude of the violation.
- For each feeder, the length of each feeder where the circuit loading exceeds criticality limits.

Figure 31: Example of single assessment results overview

Max Tx Util (%)	91.18
Tx Hours Over Rating	0

	Volt						Current Overload			
Feeder Number	Max Drop (%)	Max Rise (%)	Lower Red	Lower Amber	Upper Amber	Upper Red	Max	Amber (m)	Red (m)	Longest
1	7.5	0.00	122	0	0	0	8.3	0	0	0
2	1.8	0.00	0	0	0	0	0	0	0	0
3	5.6	0.00	43	53	0	0	0	0	0	0
4	3.7	0.00	0	4	0	0	0	0	0	0

This overview tab allows a high-level review of how congested a feeder is, but at an information resolution only which talks generally about the entire feeder without explaining where the congestion is or how long it persists for.

To allow for more detailed analysis, there are more detailed branch and node level reports (Figure 29).

Figure 32: Example of Branch loading report from single analysis

						Phasing						Maximum Current								
Feeder Number	Near Node	Far Node	Length	No of Consumers	Consumer Type	Red	Yellow	Blue	Number of Phases	Cable Type	Rating (Amps)	MC Time	MC Day	MC Season	Maximum Current (A)	Flow Direction	Above Overload Red Limit (Red Phase Hours)	Above Overload Red Limit (Yellow Phase Hours)	Above Overload Red Limit (Blue Phase Hours)	Within Overload Amber Limit (Red Phase Hours)
1	100	11	1	0		0	0	0	TRIPLE	CONSAC185	320	18:00:00	WEEKDAY	WINTER	47.8	Downstream	0.00	0.00	0.00	0.00
1	11	14	129	4	GAPEB	2	1	1		CU0.1	240	18:00:00	WEEKDAY	WINTER	45.9	Downstream	0.00	0.00	0.00	0.00
1	11	12	56	0		0	0	0		CU0.1	240	19:00:00	WEEKDAY	WINTER	9.9	Downstream	0.00	0.00	0.00	0.00
1	12	13	75	2	GAPEB	0	1	1		CU0.1	240	19:00:00	WEEKDAY	WINTER	9.9		0.00	0.00	0.00	0.00
1	14	21	5	0		0	0	0		CU0.1	240	18:00:00	WEEKDAY	WINTER	12.7	Downstream	0.00	0.00	0.00	0.00
1	14	15	1	0		0	0	0		WAVE95	235	18:00:00	WEEKDAY	WINTER	29.3	Downstream	0.00	0.00	0.00	0.00
1	15	16	6	1	GAPEB	1	0	0		WAVE95	235	18:00:00	WEEKDAY	WINTER	29.3	Downstream	0.00	0.00	0.00	0.00
1	16	17	28	0		0	0	0		CU0.06	175	18:00:00	WEEKDAY	WINTER	29.3	Downstream	0.00	0.00	0.00	0.00
1	17	20	89	4	GAPAB	1	2	1		CU0.06	175	18:00:00	WEEKDAY	WINTER	21.4		0.00	0.00	0.00	0.00
1	17	18	13	0		0	0	0		CU0.06	175	18:00:00	WEEKDAY	WINTER	21.4	Downstream	0.00	0.00	0.00	0.00
1	18	19	78	4	GAPAB	1	1	2		CU0.06	175	18:00:00	WEEKDAY	WINTER	21.4		0.00	0.00	0.00	0.00
1	21	22	84	3	GAPAB	1	1	1		CU0.3	445	18:00:00	WEEKDAY	WINTER	12.7		0.00	0.00	0.00	0.00

This report makes a one-row report for each branch in the model. The first 12 columns of the branch loading report confirm the construction details for each branch. The remaining columns of the report confirm the load flow results for each branch as follows:

- Value of maximum current load and the time and day upon which it occurred (as per DEBUT methodology)
- The amount of time that the loading of each branch resides within a criticality band. The criticality limits relate to the number of hours within the study that a branch resides within user-defined loading limits. These results are intended to allow users to decide which branches are most in need of attention.

Figure 33: Example of voltage report from single analysis

Feeder Number	Node	Number Of Consumers	Phasing: Red	Phasing: Yellow	Phasing: Blue	Highest Voltage	Day of Highest Voltage	Season of Highest Voltage	Time of Highest Voltage	Lowest Voltage	Day of Lowest Voltage	Season of Lowest Voltage	Time of Lowest Voltage
1	11	0	0	0	0	232	WEEKDAY	WINTER	03:00:00	231.99	WEEKDAY	WINTER	18:00:00
1	14	4	2	1	1	231.44	WEEKDAY	WINTER	03:00:00	229.13	WEEKDAY	WINTER	18:00:00
1	12	0	0	0	0	232.14	WEEKDAY	WINTER	19:00:00	231.72	WEEKDAY	WINTER	19:00:00
1	13	2	0	1	1	232.14	WEEKDAY	WINTER	19:00:00	231.55	WEEKDAY	WINTER	19:00:00
1	21	0	0	0	0	231.44	WEEKDAY	WINTER	03:00:00	229.11	WEEKDAY	WINTER	18:00:00
1	15	0	0	0	0	231.44	WEEKDAY	WINTER	03:00:00	229.12	WEEKDAY	WINTER	18:00:00
1	16	1	1	0	0	231.41	WEEKDAY	WINTER	03:00:00	229.03	WEEKDAY	WINTER	18:00:00
1	17	0	0	0	0	231.26	WEEKDAY	WINTER	03:00:00	228.87	WEEKDAY	WINTER	18:00:00
1	20	4	1	2	1	231.23	WEEKDAY	WINTER	03:00:00	228.42	WEEKDAY	WINTER	18:00:00
1	18	0	0	0	0	231.23	WEEKDAY	WINTER	03:00:00	228.84	WEEKDAY	WINTER	18:00:00
1	19	4	1	1	2	231.19	WEEKDAY	WINTER	03:00:00	228.3	WEEKDAY	WINTER	18:00:00
1	22	3	1	1	1	231.42	WEEKDAY	WINTER	03:00:00	229.06	WEEKDAY	WINTER	18:00:00

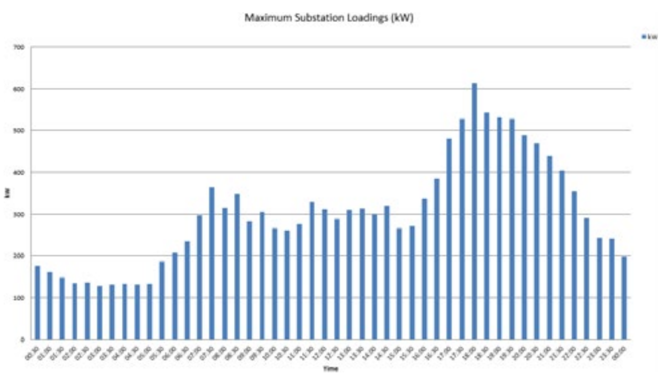
Feeder Number	Node	Above Overvoltage Red Limit (Red Phase Hours)	Above Overvoltage Red Limit (Yellow Phase Hours)	Above Overvoltage Red Limit (Blue Phase Hours)	Within Overvoltage Amber Limit (Red Phase Hours)	Within Overvoltage Amber Limit (Yellow Phase Hours)	Within Overvoltage Amber Limit (Blue Phase Hours)	Within Nominal Green Band (Red Phase Hours)	Within Nominal Green Band (Yellow Phase Hours)	Within Nominal Green Band (Blue Phase Hours)	Within Undervoltage Amber Limit (Red Phase Hours)	Within Undervolta Amber Lim (Yellow Phase Hour
1	11	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	14	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	12	1564.29	0	0	0	0	0	0	1564.29	1564.29	0	0
1	13	1564.29	0	0	0	0	0	0	1564.29	1564.29	0	0
1	21	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	15	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	16	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	17	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	20	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	18	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	19	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0
1	22	0	0	0	0	0	0	1564.29	1564.29	1564.29	0	0

The voltage results report is shown in Figure 30. This report makes a one-row report for each node in the model. The first 6 columns of the branch loading report confirm the construction details for each node. The remaining columns of the report confirm the load flow results for each branch as follows:

- Value of the highest voltage received at that node and the time day and season it was received. This value is received from the EGD load flow engine.
- Value of the lowest voltage received at that node and the time day and season it was received. This value is received from the DEBUT load flow engine.
- The remaining reporting cells explain for how many hours the node resided in user-defined criticality bandings.

Alongside detailed insight into the current substations' status, a graphical representation of substation loading is displayed across the 24-hour scenario (winter, weekdays, special day etc.). For an immediate visual understanding of any thermal issues and/or existing capacity left on the network across the day (hence informing capacity for new connections). This is illustrated in Figure 34 below.

Figure 34: Example of substation loading report for single analysis



7.1.2 Future assessment

When running future assessment, the user will be provided a summary tables as illustrated in Figure 32. This describes the maximum loading observed on the source transformer, the maximum percentage overload and how long that overload lasts for. This is important for network planners to understand the severity of the expected thermal constraint on the target substation. This is shown both with and without intervention (if an intervention is run).

The second table down in Figure 32 describes (on a feeder by feeder basis):

- The first year that an unacceptable voltage or loading condition is observed.
- The maximum and minimum voltage on a feeder within the study period.
- The number of circuit nodes that have unacceptable voltages, classified into user-defined criticality bands.

Figure 35 Example base case future assessment study.

Substation	Max Tx Util (%)	Tx Hours Over Rating			
Without intervention	123.06	10			
With intervention	123.06	10			
Without Intervention	Volt			Current Overload	
Feeder Number	Non Compliant Voltage First Year	Max Drop (%) Over Period	Max Rise(%) Over Period	Non Compliance Current First Year	Maximum Over Period (A)
1	2034	3.2	0.0000		0
2	2020	7.3	0.0000	2029	296.2
3	2018	10.9	0.0000	2029	155.1
4	2027	6.7	0.0000		0
5	2018	12.2	0.0000		0
6	2033	3.2	0.0000		0

The example shown illustrates a network which has:

- By the end of the study period, an unacceptable level of load on the transformer.
- Some current underlying feeder voltage issues on feeder 3 and 5 and from 2020 onwards electrical growth will drive each of the six feeders to display low voltages.

- Demonstration that feeder 2 will begin overloading in 2029 and by the end of the study period will have the worst overloaded branch, which will exceed its rating by 296 Amps. This is followed by feeder three which will also start overloaded in 2029 and by the end of the study period, it's worst serving branch will exceed rating by 155 Amps.

If a SAVE intervention were to be run on this substation the user could conduct additional analysis in the future assessment tool to investigate the ability of SAVE solutions to either eliminate or defer the need for conventional reinforcement.

Figure 33 shows the results of this analysis, which indicates as expected that under base case load growth conditions, feeder 2 runs out of thermal capacity in the year 2029 and that by the end of the study period the worst point of the feeder is 296 amps over its rating. This figure also shows the results for this network if a SAVE (LED trial) intervention is triggered across this network in the year 2029. These results show that deployment of the SAVE intervention defers the timing of the overload from 2029 to 2030 and reduces the total size of the overload observed. This would imply that LED's are a technically feasible choice to defer the alternative capital investment that this example would otherwise demand.

Figure 36: Comparison of investment timing with and without energy efficiency interventions

Without Intervention	Volt			Current Overload	
Feeder Number	Non Compliant Voltage First Year	Max Drop (%) Over Period	Max Rise(%) Over Period	Non Compliance Current First Year	Maximum Over Period (A)
1	2034	3.2	0.0000		0
2	2020	7.3	0.0000	2029	296.2
3	2018	10.9	0.0000	2029	155.1
4	2027	6.7	0.0000		0
5	2018	12.2	0.0000		0
6	2033	3.2	0.0000		0

With Intervention	Volt			Current Overload	
Feeder Number	Non Compliant Voltage First Year	Max Drop (%) Over Period	Max Rise(%) Over Period	Non Compliance Current First Year	Maximum Over Period (A)
1		2.8	0.0000		0
2	2020	7.6	0.0000	2030	285.6
3	2018	10.5	0.0000	2029	148.3
4	2027	6.7	0.0000		0
5	2018	12.1	0.0000		0
6	2031	3.2	0.0000		0

The purpose of the report shown in Figure 33 is to show an overview of the loading and voltage indices for the entire substation which can be quickly assimilated. Once a problem has been detected in a network, users can also study the effect of either energy efficiency interventions which change customer behaviour or alternatively network led interventions through use of more detailed branch or loading reports.

It is often important to understand what technical interventions will work on particular network problems. As an example, the network exhibited in Figure 33 indicates that feeder 2 will have a large overload develop over the period 2029 to 2034. Analysis of the detailed branch results in Figure 34 for feeder 2 in shows that in the year 2034, this feeder has two overloads which are revealed to have the following details:

- Overload 1, which is the branch between the source (node 100) and node 2, which is a length of 4 metres and will seek to carry 631 Amps, which represents an overload of 296 Amps by the end of the study period.

- Overload 2, which is the branch between node 48 and 49. This branch has a length of 99 metres and carrying 289 Amps by the end of the study period,

The size of overload 1 is significant, as 631 Amps is larger than the maximum size of LV cable that DNO's tend to procure as standard, so in this case, it may not be feasible to overload this short section of cable, which implies an alternative reinforcement is required.

From Figure 35 It can also be seen from that overload 1 and overload 2 both lie on the same feeding path. Because these two overloads are stacked and because of the comparatively long branch associated with feeder 2 then it may appear that splitting the feeder at a point beneath node 49 may be a technically feasible approach. This can also be tested by the future assessment tool, and the summary results are shown in Figure 36 with the detailed results shown in Figure 37. Review of these results shown have overloads 1 and 2 have changed in the following manner:

- Overload 1, there is still an overload expected between the source (node 100) and node 2, which is a length of 4 metres. But unlike the base case condition, this branch will now only be overloaded by 40 Amps by the end of the study period.

- Overload 2, was is the branch between node 48 and 49 has now been moved to a new feeder called feeder 7 and it can be seen that there is no overload on this feeder at all.

This analysis would suggest then that the most effective network led solution to resolve the issues on feeder 2 would be to split the feeder into two and to overlay the first four metres of the original feeder 2.

Figure 37: Example base case future assessment study.

						Phasing						Maximum Current			
Feeder Number	Near Node	Far Node	Length	No of Consumers	Consumer Type	Red	Yellow	Blue	Number of Phases	Cable Type	Rating (Amps)	MC Time	MC Day	MC Season	Maximum Current (A)
2	100	2	4	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	631.2
2	60	61	20	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	48.9
2	59	60	18	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	48.9
2	58	59	2	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	48.9
2	56	57	52	0		0	0	0	TRIPLE	AL 0.15	225	22:00:00	WEEKDAY	WINTER	32
2	55	56	25	0		0	0	0	TRIPLE	AL 0.15	225	22:00:00	WEEKDAY	WINTER	52.5
2	55	58	7	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	48.9
2	54	55	4	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	88.8
2	53	54	2	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	103.2
2	52	53	3	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	114.1
2	50	51	56	0		0	0	0	TRIPLE	CONSAC 95	220	22:00:00	WEEKDAY	WINTER	30.4
2	50	52	32	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	152.1
2	49	50	10	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	184
2	48	49	99	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	289.8
2	47	48	32	0		0	0	0	TRIPLE	CU 0.2	345	21:00:00	WEEKDAY	WINTER	289.8
2	45	46	118	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	189.6
2	44	45	20	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	189.6
2	42	43	59	0		0	0	0	TRIPLE	CU 0.1	240	03:00:00	WEEKDAY	WINTER	0
2	41	42	20	0		0	0	0	TRIPLE	CU 0.1	240	03:00:00	WEEKDAY	WINTER	0
2	39	40	26	0		0	0	0	TRIPLE	CONSAC 95	220	22:00:00	WEEKDAY	WINTER	32
2	39	41	80	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	102.3
2	38	44	29	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	189.6
2	38	39	8	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	125.3
2	35	36	8	0		0	0	0	TRIPLE	WAVE 185	335	03:00:00	WEEKDAY	WINTER	0
2	34	35	15	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	40.6
2	34	38	76	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	292.8
2	33	37	149	0		0	0	0	TRIPLE	CU 0.04	140	21:00:00	WEEKDAY	WINTER	46.6
2	33	34	2	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	312.3
2	32	33	33	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	352.2
2	31	32	10	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	375.2
2	30	31	2	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	375.2
2	29	30	20	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	375.2
2	29	47	2	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	289.8
2	2	29	2	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	631.2
2	61	248	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	46.6
2	61	249	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	57	250	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	32
2	56	251	1	0		0	0	0	TRIPLE	WAVE 300	435	12:30:00	WEEKDAY	WINTER	42
2	56	252	1	0		0	0	0	TRIPLE	WAVE 300	435	01:30:00	WEEKDAY	WINTER	12.1
2	54	253	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	53	254	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	35.8
2	51	255	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	52	256	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	51.3
2	50	257	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	33.2
2	49	258	1	0		0	0	0	TRIPLE	WAVE 300	435	12:30:00	WEEKDAY	WINTER	46.3
2	49	259	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	47.3
2	49	260	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	68.5
2	49	261	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	46	262	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	57.3
2	46	263	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	61
2	46	264	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	89.9
2	46	265	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	40	266	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	32
2	41	267	1	0		0	0	0	TRIPLE	WAVE 300	435	12:30:00	WEEKDAY	WINTER	42
2	41	268	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	68.2
2	41	269	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	39	270	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	35	271	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	40.6
2	37	272	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	46.6
2	33	273	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	32
2	32	274	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	39.1

Figure 38: Example base case future assessment study.

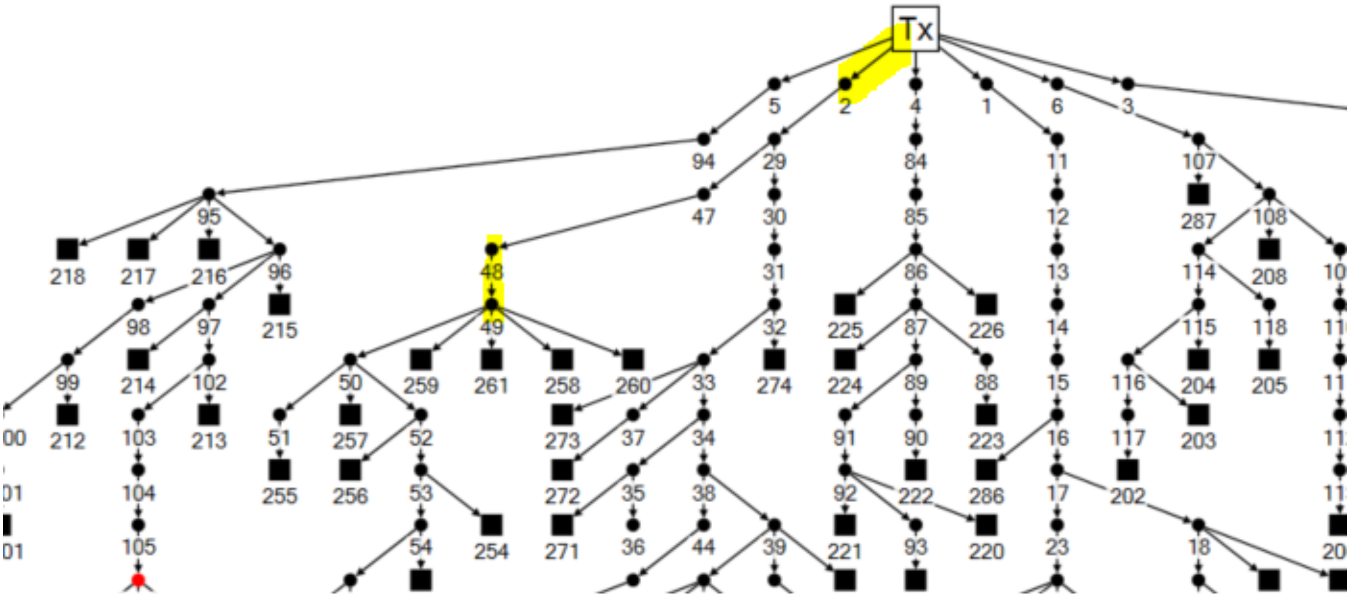


Figure 39: Example base case future assessment study.

With Intervention	Volt			Current Overload	
Feeder Number	Non Compliant Voltage First Year	Max Drop (%) Over Period	Max Rise(%) Over Period	Non Compliance Current First Year	Maximum Over Period (A)
1	2034	3.2	0.0000		0
2	2023	7.2	0.0000	2034	40.2
3	2018	10.9	0.0000	2029	155.1
4	2027	6.7	0.0000		0
5	2018	12.2	0.0000		0
6	2033	3.2	0.0000		0
7		2.9	0.0000		0

Figure 40: Example of branch results after intervention

						Phasing						Maximum Current			
Feeder Number	Near Node	Far Node	Length	No of Consumers	Consumer Type	Red	Yellow	Blue	Number of Phases	Cable Type	Rating (Amps)	MC Time	MC Day	MC Season	Maximum Current (A)
2	100	2	4	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	375.2
2	47	48	32	0		0	0	0	TRIPLE	CU 0.2	345	03:00:00	WEEKDAY	WINTER	0
2	45	46	118	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	189.6
2	44	45	20	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	189.6
2	42	43	59	0		0	0	0	TRIPLE	CU 0.1	240	03:00:00	WEEKDAY	WINTER	0
2	41	42	20	0		0	0	0	TRIPLE	CU 0.1	240	03:00:00	WEEKDAY	WINTER	0
2	39	40	26	0		0	0	0	TRIPLE	CONSAC 95	220	22:00:00	WEEKDAY	WINTER	32
2	39	41	80	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	102.3
2	38	44	29	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	189.6
2	38	39	8	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	125.3
2	35	36	8	0		0	0	0	TRIPLE	WAVE 185	335	03:00:00	WEEKDAY	WINTER	0
2	34	35	15	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	40.6
2	34	38	76	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	292.8
2	33	37	149	0		0	0	0	TRIPLE	CU 0.04	140	21:00:00	WEEKDAY	WINTER	46.6
2	33	34	2	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	312.3
2	32	33	33	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	352.2
2	31	32	10	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	375.2
2	30	31	2	0		0	0	0	TRIPLE	CU 0.25	395	21:00:00	WEEKDAY	WINTER	375.2
2	29	30	20	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	375.2
2	29	47	2	0		0	0	0	TRIPLE	WAVE 185	335	03:00:00	WEEKDAY	WINTER	0
2	2	29	2	0		0	0	0	TRIPLE	WAVE 185	335	21:00:00	WEEKDAY	WINTER	375.2
2	46	262	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	57.3
2	46	263	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	61
2	46	264	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	89.9
2	46	265	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	40	266	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	32
2	41	267	1	0		0	0	0	TRIPLE	WAVE 300	435	12:30:00	WEEKDAY	WINTER	42
2	41	268	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	68.2
2	41	269	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	39	270	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
2	35	271	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	40.6
2	37	272	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	46.6
2	33	273	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	32
2	32	274	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	39.1
7	60	61	20	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	48.9
7	59	60	18	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	48.9
7	58	59	2	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	48.9
7	56	57	52	0		0	0	0	TRIPLE	AL 0.15	225	22:00:00	WEEKDAY	WINTER	32
7	55	56	25	0		0	0	0	TRIPLE	AL 0.15	225	22:00:00	WEEKDAY	WINTER	52.5
7	55	58	7	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	48.9
7	54	55	4	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	88.8
7	53	54	2	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	103.2
7	52	53	3	0		0	0	0	TRIPLE	WAVE 95	235	21:00:00	WEEKDAY	WINTER	114.1
7	50	51	56	0		0	0	0	TRIPLE	CONSAC 95	220	22:00:00	WEEKDAY	WINTER	30.4
7	50	52	32	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	152.1
7	491	50	10	0		0	0	0	TRIPLE	CU 0.1	240	21:00:00	WEEKDAY	WINTER	184
7	491	49	99	0		0	0	0	TRIPLE	CU 0.1	240	03:00:00	WEEKDAY	WINTER	0
7	61	248	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	46.6
7	61	249	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
7	57	250	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	32
7	56	251	1	0		0	0	0	TRIPLE	WAVE 300	435	12:30:00	WEEKDAY	WINTER	42
7	56	252	1	0		0	0	0	TRIPLE	WAVE 300	435	01:30:00	WEEKDAY	WINTER	12.1
7	54	253	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
7	53	254	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	35.8
7	51	255	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
7	52	256	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	51.3
7	50	257	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	33.2
7	491	258	1	0		0	0	0	TRIPLE	WAVE 300	435	12:30:00	WEEKDAY	WINTER	46.3
7	491	259	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	47.3
7	491	260	1	0		0	0	0	TRIPLE	WAVE 300	435	21:00:00	WEEKDAY	WINTER	68.5
7	491	261	1	0		0	0	0	TRIPLE	WAVE 300	435	22:00:00	WEEKDAY	WINTER	30.4
7	100	491	139	0		0	0	0	TRIPLE	CU 0.5	570	21:00:00	WEEKDAY	WINTER	289.8

Figure 41: Future Assessment full results

	Voltage					Thermal										
	Max Volt Drop					Max Cable Utilisation						Max Transformer Utilisation				
Year	Volt Drop (%)	Volt Drop Node	Volt Drop Time	Volt Drop Day	Volt Drop Season	Max Utilisation (%)	Near Node	Far Node	Cable Utilisation Time	Cable Utilisation Day	Cable Utilisation Season	Max Tx Utilisation (%)	Tx Utilisation Time	Tx Utilisation Day	Tx Utilisation Season
2018	4.6	106	18:00:00	WEEKDAY	WINTER	69.8	100	2	18:00:00	WEEKDAY	WINTER	42.22	18:00:00	WEEKDAY	WINTER
2019	4.6	106	18:00:00	WEEKDAY	WINTER	71.9	100	2	18:00:00	WEEKDAY	WINTER	42.76	18:00:00	WEEKDAY	WINTER
2020	4.8	106	18:00:00	WEEKDAY	WINTER	73.7	100	2	18:00:00	WEEKDAY	WINTER	43.09	18:00:00	WEEKDAY	WINTER
2021	4.8	106	18:00:00	WEEKDAY	WINTER	75.5	100	2	18:00:00	WEEKDAY	WINTER	44.58	18:00:00	WEEKDAY	WINTER
2022	4.8	106	18:00:00	WEEKDAY	WINTER	79	100	2	18:00:00	WEEKDAY	WINTER	45.74	18:00:00	WEEKDAY	WINTER
2023	5.4	106	18:00:00	WEEKDAY	WINTER	81.5	100	2	18:00:00	WEEKDAY	WINTER	47.19	18:00:00	WEEKDAY	WINTER
2024	5.2	106	18:00:00	WEEKDAY	WINTER	77.9	100	2	18:00:00	WEEKDAY	WINTER	48.26	18:00:00	WEEKDAY	WINTER
2025	5.5	71	18:00:00	WEEKDAY	WINTER	85.9	66	67	18:00:00	WEEKDAY	WINTER	49.69	18:30:00	WEEKDAY	WINTER
2026	5.9	78	17:30:00	WEEKDAY	WINTER	90.3	66	67	18:00:00	WEEKDAY	WINTER	51.92	18:30:00	WEEKDAY	WINTER
2027	6.5	106	18:00:00	WEEKDAY	WINTER	96.3	100	2	18:00:00	WEEKDAY	WINTER	56.89	21:00:00	WEEKDAY	WINTER
2028	6.7	106	21:00:00	WEEKDAY	WINTER	105	100	2	21:00:00	WEEKDAY	WINTER	64	21:00:00	WEEKDAY	WINTER
2029	7.9	106	21:00:00	WEEKDAY	WINTER	114	100	2	21:00:00	WEEKDAY	WINTER	73.07	21:00:00	WEEKDAY	WINTER
2030	9.5	106	18:30:00	WEEKDAY	WINTER	130	66	67	21:00:00	WEEKDAY	WINTER	82.58	21:00:00	WEEKDAY	WINTER
2031	9.4	106	21:00:00	WEEKDAY	WINTER	147	100	2	21:00:00	WEEKDAY	WINTER	92.17	21:00:00	WEEKDAY	WINTER
2032	10.6	106	22:00:00	WEEKDAY	WINTER	166	66	67	21:00:00	WEEKDAY	WINTER	101.17	21:30:00	WEEKDAY	WINTER
2033	11.4	106	21:00:00	WEEKDAY	WINTER	175	100	2	21:00:00	WEEKDAY	WINTER	109.9	21:30:00	WEEKDAY	WINTER
2034	12.2	106	21:00:00	WEEKDAY	WINTER	189	66	67	21:00:00	WEEKDAY	WINTER	123.06	21:30:00	WEEKDAY	WINTER

7.2 Case study

Figure 40 shows an example of the multi-scenario cost output.

Figure 42: Multi-scenario cost output

Assessment Year 1	Strategy	Low Growth Outcome Scenario1	Mid Growth Outcome Scenario2	High Growth Outcome Scenario3	Very High Growth Outcome Scenario4
2025	All Knowing	£ -	£ 39.94	£ 411,515.78	£ -
	Flexibility Min	£ -	£ 28,833.76	£ 52,241.61	£ -
	Flexibility Max	£ -	£ 39.94	£ 52,241.61	£ -
	Minimum	£ -	£ 39.94	£ 52,241.61	£ -
	Maximum	£ -	£ 28,833.76	£ 411,515.78	£ -

Regret	Least Regret	Least Regret	Least Regret	Least Regret	Worst Regret
All Knowing	£ -	£ -	£ 359,274.17	£ -	£ 359,274.17
Flexibility Min	£ -	£ 28,793.83	£ -	£ -	£ 28,793.83
Flexibility Max	£ -	£ -	£ -	£ -	£ -
				Least Worst Regret	£ -

Assessment Year 2	Strategy	Low Growth Outcome Scenario1	Mid Growth Outcome Scenario2	High Growth Outcome Scenario3	Very High Growth Outcome Scenario4
2030	All Knowing	£ 41,092.28	£ 265,606.81	£ 411,515.78	£ -
	Flexibility Min	£ 22,533.69	£ 47,666.82	£ 139,943.50	£ -
	Flexibility Max	£ 22,533.69	£ 47,666.82	£ 139,943.50	£ -
	Minimum	£ 22,533.69	£ 47,666.82	£ 139,943.50	£ -
	Maximum	£ 41,092.28	£ 265,606.81	£ 411,515.78	£ -

Regret					Worst Regret
All Knowing	£ 18,558.60	£ 217,940.00	£ 271,572.28	£ -	£ 271,572.28
Flexibility Min	£ -	£ -	£ -	£ -	£ -
Flexibility Max	£ -	£ -	£ -	£ -	£ -
				Least Worst Regret	£ -

Assessment Year 3	Strategy	Low Growth Outcome Scenario1	Mid Growth Outcome Scenario2	High Growth Outcome Scenario3	Very High Growth Outcome Scenario4
2035	All Knowing	£ 41,092.28	£ 363,537.54	£ 640,040.13	£ -
	Flexibility Min	£ 56,283.81	£ 247,391.36	£ 456,266.66	£ -
	Flexibility Max	£ 56,283.81	£ 247,391.36	£ 456,266.66	£ -
	Minimum	£ 41,092.28	£ 247,391.36	£ 456,266.66	£ -
	Maximum	£ 56,283.81	£ 363,537.54	£ 640,040.13	£ -

Regret					Worst Regret
All Knowing	£ -	£ 116,146.18	£ 183,773.48	£ -	£ 183,773.48
Flexibility Min	£ 15,191.52	£ -	£ -	£ -	£ 15,191.52
Flexibility Max	£ 15,191.52	£ -	£ -	£ -	£ 15,191.52
				Least Worst Regret	£ 15,191.52

Assessment Year 4	Strategy	Low Growth Outcome Scenario1	Mid Growth Outcome Scenario2	High Growth Outcome Scenario3	Very High Growth Outcome Scenario4
2040	All Knowing	£ 41,092.28	£ 363,537.54	£ 640,040.13	£ -
	Flexibility Min	£ 56,283.81	£ 256,518.69	£ 484,051.74	£ -
	Flexibility Max	£ 56,283.81	£ 256,518.69	£ 484,051.74	£ -
	Minimum	£ 41,092.28	£ 256,518.69	£ 484,051.74	£ -
	Maximum	£ 56,283.81	£ 363,537.54	£ 640,040.13	£ -

Regret					Worst Regret
All Knowing	£ -	£ 107,018.86	£ 155,988.39	£ -	£ 155,988.39
Flexibility Min	£ 15,191.52	£ -	£ -	£ -	£ 15,191.52
Flexibility Max	£ 15,191.52	£ -	£ -	£ -	£ 15,191.52
				Least Worst Regret	£ 15,191.52

Figure 41 below shows an example of the detailed multi-scenario output for the low growth scenario, identifying the cost and timing of solutions for each strategy.

Figure 43: Multi-scenario Low Growth Strategies

Scenario	Strategy	Year	Intervention	Action	Actual Cost	NPV to Evaluation Year
Scenario 1 Low Growth	All Knowing Strategy	2028	Transformer	1) Upgrade capacity to 1000KVA	28,700.0	41,092.3
		2029	Overlay Feeder 4	1) Node 100 to node 4 distance 6m with WAVE 600	36,800.0	
				2) Node 4 to node 38 distance 34m with WAVE 600		
	Flexibility Minimum	2028	Transformer	1) Upgrade capacity to 750KVA	26,500.0	56,283.8
		2029	Overlay Feeder 4	1) Node 100 to node 4 distance 6m with WAVE 300	8,880.0	
		2031	Overlay Feeder 4	1) Node 4 to node 38 distance 34m with WAVE 600	26,240.0	
		2033	Overlay Feeder 4	1) Node 100 to node 4 distance 6m with WAVE 600	10,560.0	
		2034	Transformer	1) Upgrade capacity to 1000KVA	28,700.0	
	Flexibility Maximum	2028	Transformer	1) Upgrade capacity to 750KVA	26,500.0	56,283.8
		2029	Overlay Feeder 4	1) Node 100 to node 4 distance 6m with WAVE 300	8,880.0	
		2031	Overlay Feeder 4	1) Node 4 to node 38 distance 34m with WAVE 600	26,240.0	
		2033	Overlay Feeder 4	1) Node 100 to node 4 distance 6m with WAVE 600	10,560.0	
		2034	Transformer	1) Upgrade capacity to 1000KVA	28,700.0	

Figure 42 and Figure 43 show an example of the future-scenario output for the Medium Growth scenario, without then with the LED light bulb intervention. This shows how, when the intervention is deployed, it helps to keep the cable and transformer utilisation below 100% compared to when it is not in place.

Figure 44: Future Scenario, Medium Growth without LED's

Year	Max Utilisation (%)	Near Node	Far Node	Cable Utilisation Time	Cable Utilisation Day	Cable Utilisation Season	Max Tx Utilisation (%)	Tx Utilisation Time	Tx Utilisation Day	Tx Utilisation Season
2019	90.2	100	4	18:00:00	WEEKDAY	WINTER	91.26	18:00:00	WEEKDAY	WINTER
2020	91.9	100	4	18:00:00	WEEKDAY	WINTER	91.44	18:00:00	WEEKDAY	WINTER
2021	94	100	4	18:00:00	WEEKDAY	WINTER	91.78	18:00:00	WEEKDAY	WINTER
2022	95.2	100	4	18:00:00	WEEKDAY	WINTER	94.84	18:00:00	WEEKDAY	WINTER
2023	97	100	4	18:00:00	WEEKDAY	WINTER	95.5	18:00:00	WEEKDAY	WINTER
2024	100	100	4	18:00:00	WEEKDAY	WINTER	96.34	18:00:00	WEEKDAY	WINTER
2025	98.7	100	4	18:00:00	WEEKDAY	WINTER	97.92	18:00:00	WEEKDAY	WINTER
2026	103	100	4	18:30:00	WEEKDAY	WINTER	101.72	21:00:00	WEEKDAY	WINTER
2027	112	100	4	21:00:00	WEEKDAY	WINTER	110.98	21:00:00	WEEKDAY	WINTER
2028	123	100	4	21:00:00	WEEKDAY	WINTER	121.22	21:00:00	WEEKDAY	WINTER
2029	136	100	4	21:00:00	WEEKDAY	WINTER	134.42	21:00:00	WEEKDAY	WINTER
2030	150	100	4	21:00:00	WEEKDAY	WINTER	148.86	21:00:00	WEEKDAY	WINTER
2031	166	100	4	21:00:00	WEEKDAY	WINTER	164.06	21:00:00	WEEKDAY	WINTER
2032	183	100	4	21:00:00	WEEKDAY	WINTER	176.92	21:30:00	WEEKDAY	WINTER
2033	193	100	4	21:00:00	WEEKDAY	WINTER	190.82	21:30:00	WEEKDAY	WINTER
2034	215	100	4	21:30:00	WEEKDAY	WINTER	211.4	21:30:00	WEEKDAY	WINTER
2035	236	100	4	21:30:00	WEEKDAY	WINTER	235.32	21:30:00	WEEKDAY	WINTER
2036	236	100	4	21:30:00	WEEKDAY	WINTER	236.3	21:30:00	WEEKDAY	WINTER
2037	236	100	4	21:30:00	WEEKDAY	WINTER	236.3	21:30:00	WEEKDAY	WINTER
2038	237	100	4	21:30:00	WEEKDAY	WINTER	236.8	21:30:00	WEEKDAY	WINTER
2039	237	100	4	21:30:00	WEEKDAY	WINTER	236.8	21:30:00	WEEKDAY	WINTER
2040	237	100	4	21:30:00	WEEKDAY	WINTER	237.28	21:30:00	WEEKDAY	WINTER

Figure 45: Future Scenario, Medium Growth with LED's

	Thermal									
	Max Cable Utilisation						Max Transformer Utilisation			
Year	Max Utilisation (%)	Near Node	Far Node	Cable Utilisation Time	Cable Utilisation Day	Cable Utilisation Season	Max Tx Utilisation (%)	Tx Utilisation Time	Tx Utilisation Day	Tx Utilisation Season
2019	90.2	100	4	18:00:00	WEEKDAY	WINTER	91.26	18:00:00	WEEKDAY	WINTER
2020	91.9	100	4	18:00:00	WEEKDAY	WINTER	91.44	18:00:00	WEEKDAY	WINTER
2021	94	100	4	18:00:00	WEEKDAY	WINTER	91.78	18:00:00	WEEKDAY	WINTER
2022	95.2	100	4	18:00:00	WEEKDAY	WINTER	94.84	18:00:00	WEEKDAY	WINTER
2023	97	100	4	18:00:00	WEEKDAY	WINTER	95.5	18:00:00	WEEKDAY	WINTER
2024	91.6	100	4	18:30:00	WEEKDAY	WINTER	92.04	18:30:00	WEEKDAY	WINTER
2025	95.5	100	4	18:30:00	WEEKDAY	WINTER	94.06	18:30:00	WEEKDAY	WINTER
2026	97.3	100	4	21:00:00	WEEKDAY	WINTER	97.1	18:30:00	WEEKDAY	WINTER
2027	106	100	4	21:00:00	WEEKDAY	WINTER	106.2	21:00:00	WEEKDAY	WINTER
2028	118	100	4	21:00:00	WEEKDAY	WINTER	116.44	21:00:00	WEEKDAY	WINTER
2029	131	100	4	21:00:00	WEEKDAY	WINTER	129.64	21:00:00	WEEKDAY	WINTER
2030	148	100	4	21:00:00	WEEKDAY	WINTER	144.08	21:00:00	WEEKDAY	WINTER
2031	161	100	4	21:00:00	WEEKDAY	WINTER	160.14	21:30:00	WEEKDAY	WINTER
2032	177	100	4	21:00:00	WEEKDAY	WINTER	173.22	21:30:00	WEEKDAY	WINTER
2033	190	100	4	21:30:00	WEEKDAY	WINTER	187.12	21:30:00	WEEKDAY	WINTER
2034	208	100	4	21:30:00	WEEKDAY	WINTER	207.7	21:30:00	WEEKDAY	WINTER
2035	230	100	4	21:30:00	WEEKDAY	WINTER	231.62	21:30:00	WEEKDAY	WINTER
2036	233	100	4	21:30:00	WEEKDAY	WINTER	232.6	21:30:00	WEEKDAY	WINTER
2037	233	100	4	21:30:00	WEEKDAY	WINTER	232.6	21:30:00	WEEKDAY	WINTER
2038	235	100	4	21:30:00	WEEKDAY	WINTER	233.08	21:30:00	WEEKDAY	WINTER
2039	235	100	4	21:30:00	WEEKDAY	WINTER	233.08	21:30:00	WEEKDAY	WINTER
2040	235	100	4	21:30:00	WEEKDAY	WINTER	233.58	21:30:00	WEEKDAY	WINTER