Prototype Real Options Model: Tool Description

Part of the 'Network Innovation Allowance' Project
'Demand Scenarios with Electric Heat and Commercial Capacity Options'

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CONTENTS

GLOSSARY

ASC	Average Cold Spell – National Grid's approach to weather-correct peak load for average winter weather conditions
CAM	Cost Assessment Module
CBA	Cost Benefit Analysis
C2C	Electricity North West's Second Tier LCNF project (2012-2014) which proved post-fault demand response with network automation was technically feasible and deliverable to customers.(www.enwl.co.uk/c2c)
CvaR	Conditional Value at Risk
DNO	Distribution Network Operator
DSR	Demand Side Response
EV	Electric Vehicle
Grid and primary (G&P)	network or substations including Grid Supply Points, Bulk Supply Points and primary substations
IELM	Initial Excess Load Module
ISM	Intervention Scheduling Module
NOP	Normal Open Point
PFM	Probabilistic Forecasting Module
RIIO-ED1	Revenue = Innovation Incentives Outputs – Electricity Distribution 1 The current regulatory period for DNOs – 1st April 2015 -31st March 2023.
RELM	Residual Excess Load Module
RO	Real Options
VaR	Value at Risk

VERSION HISTORY

Version	Date	Author	Status	Comments
Draft	March 2016	C. Kaloudas / R. Shaw		
Final	December 2016	R. Shaw		

REVIEW

Name	Role	Date

APPROVAL

Name	Role	Date

EXECUTIVE SUMMARY

This report describes Electricity North West's Real Options (RO) Cost Benefit Analysis (CBA) tool for Grid and primary (G&P) investment decisions. The developed RO tool can be used to support decisions on if, how and when Capacity to Customer (C_2C) Demand Side Response (DSR) services versus traditional network reinforcements should be implemented by Distribution Network Operators (DNOs) in the context of general reinforcement. The tool is not meant to assess the use of C_2C to avoid reinforcement for new connections, where the principal benefit is the reduced cost of connection for a specific customer, rather than a change in the DNO's reinforcement costs.

In particular, this report presents:

- a description of the latest available RO tool, using a structured definition of computational modules and presenting the associated processes using flowcharts;
- a proposed use (recommended analysis) of the RO tool together with other processes outside the tool;
- the advantages and disadvantages of the RO tool with respect to the spreadsheet modelling approach; and,
- suggestions for improvement of the RO tool.

This report provides a better understanding of the computational processes of the latest available RO tool. More specifically, the tool processes are explained by means of computational modules. In order to show how the user-defined inputs are used to provide cost- and risk-related results, flowcharts are presented and practical insights are described for every computational module. The RO tool follows a spreadsheet modelling approach, thus the algorithmic/ flowchart-based description of its computational modules allow a potential script-based development of future RO tool versions.

A recommended analysis is also proposed using the RO tool together with other processes outside the tool to compare strategies involving post-fault C_2C DSR interventions versus traditional network. The suggested approach suggests that cost assessment using the RO tool are based both on commercial and customer (i.e., societal benefits) perspectives. Additionally, effects of the reduction in energy losses and the depreciation of assets are taken into account in cost assessments in line with Ofgem's Cost Benefit Analysis outside the Real Option Tool.

Following the proposed use of the RO tool, the network planner can identify cases where one strategy exhibits profound advantages over its alternatives. The assessment of net present cost in this case can be the dominant objective in the decision making process. Nonetheless, it should be noted that in the confusing cases where no strategy exhibits profound benefits to its alternatives, network planner can use the RO tool within the context of the recommended analysis to follow a multi-objective rather than a single objective approach in decision making.

The advantages and disadvantages of the latest version of the RO tool are also discussed. In general, the RO tool advantages include the negligible computational cost and the easy use from experienced Excel users. On the contrary, the tool disadvantages mainly concern the complexity regarding its outputs and the difficulty in updating the tool due to the spreadsheet-based modelling.

Although the prototype RO tool is now usable to support DNO business-decisions including the scheduling of realistic DNO-defined interventions, there should be a continuous focus on potential tool improvements.

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1 INTRODUCTION

This report describes Electricity North West's Real Options (RO) Cost Benefit Analysis (CBA) tool for Grid and Primary (G&P) investment decisions. The developed RO tool can be used to support decisions on if, how and when to implement the Capacity to Customer (C_2C) Demand Side Response (DSR) service versus or in combination with traditional distribution network reinforcements undertaken by a Distribution Network Operator (DNO).

Background information regarding the effects of growing electricity demand, and the C_2C methodology are presented in subsections 1.1 to 1.3. In Section 2, the current version of the RO model is presented using flowcharts that describe the corresponding computational modules and processes, as well as the RO tool inputs and outputs.

Section 3 presents a recommended analysis using the RO tool together with processes outside the tool and discusses practical aspects regarding the decision making process. The main characteristics of the current RO tool are summarized in Section 3, whereas suggestions for future work are described in Section 4.

Finally, concluding remarks are drawn in Section 5.

1.1 Network Planning: Effects from Growing Demand

As GB fulfils its decarbonisation obligations under the Climate Change Act 2008, to cut greenhouse gas emissions by 80% by 2050, the demand on electricity networks is likely to increase significantly. This increase in network demand will be driven primarily through the decarbonisation of heat, transportation and local electricity production rather than by population growth.

Meeting growing demand requires additional network capacity and using traditional capital intensive reinforcement techniques would require significant investment [1]. A 2009 Ofgem consultation document estimated that required investment in the GB transmission and distribution network could be as much as £53.4bn between 2009 and 2025. Investment requirements are driven by the current planning and design standard, Engineering Recommendation P2/6 (ER P2/6), which requires, in broad terms, that for every extra 10 MW of capacity required, 20 MW of infrastructure is needed. Such investment would have to be paid for by customers through higher connection and use of system charges.

Addressing the provision of capacity using traditional reinforcement will also have a significant impact on carbon emissions and the wider society. The techniques that traditional reinforcement uses are also very intrusive for local communities and can often involve extensive excavations and disruption. Average reinforcement timescales are in the region of 12-16 weeks for work involving cable upgrades or switchgear and much longer when involving new transformers or more complicated work.

1.2 Capacity to Customers (C_2C) Method

The traditional asset-based approach to the provision of additional demand or generation capacity is unable to facilitate the decarbonisation of energy and transport at an affordable cost and will tend to act as a barrier to successfully achieving carbon reduction targets. The C_2C method [1] releases capacity through a combination of innovative network management technologies in conjunction with new customer commercial arrangements.

Current EHV and HV networks use redundancy and network interconnection to achieve security of supply standards. Network feeders are interconnected by a normally open point (NOP) which is only utilised in the event of a network fault or planned outage. It is of note that nearly half of circuits do not suffer any faults, and one third experience faults lasting 1 – 2 hours in any five-year period. Under such conditions, closing the NOP allows all customers affected by a fault outage to be re-supplied from the alternative circuit. This means EHV and

HV circuits at peak typically operate at only 50 - 60% of their rated capacity. It is this inherent capacity that the C_2C method seeks to release for use by customers for the connection of new loads and generation.

Specifically the C_2C method redesigns the network with additional automation to allow the NOP to be closed (either in normal operation or after a fault), allowing the whole capacity of the ring to be used by joining the two circuits. To ensure that security of customer supply is maintained and supplies can be restored during fault outages, the C_2C method has developed and trialled new post-fault demand response contracts which will allow Electricity North West to either reduce consumption or reduce generation depending upon the nature of the post fault constraint being addressed.

Post-fault demand response can be introduced for existing customers or for new connections. When a new customer connects to the network they will be offered the option to sign up to a managed contract in exchange for a reduced connection charge (equivalent to the saving of reinforcement costs). The current RO tool assesses the costs and risks associated with offering these contracts to existing customers.

The C_2C method is highly transferable across GB and will accelerate a low carbon future by releasing a significant amount of distribution network pre-existing capacity. This capacity can be used to play a significant part in meeting the UK's carbon emission objectives.

2 DESCRIPTION OF THE PROTOTYPE REAL OPTIONS TOOL

The Real Options (RO) modelling approach described in [2] is followed in the Excel-based (i.e., spreadsheet) RO tool. This tool can be used by Electricity North West and any other DNO to understand from a network planning perspective the potential advantages from the deployment of strategies that involve post-fault C_2C DSR [1] versus traditional network reinforcement interventions. Such connections are now generally referred to as ‘managed connections’ with existing demand customers, rather than C_2C connections.

In the following subsections, the Real Options Modelling concept in decision making is first briefly explained focusing on a) the type of interventions considered in the RO tool and b) the overview of the tool computational modules. Next, all processes, inputs and outputs associated with the computational modules of the RO tool are described in detail.

2.1 Real Options Modelling

Real Options analysis should be implemented when favourable conditions allow the contractual right to take optional actions [2]. Real Options do not “create” flexibility, but highlight in a quantitative way the value of the flexibility that is available in decision making, which is particularly important in a network investment context.

As highlighted in [2], two fundamental types of flexibility exist in engineering projects, which are:

- the flexibility in the timing of a decision; and,
- the flexibility in the design of the project.

A Real Options analysis approach using the C_2C methodology is followed in the latest available version of the Real Options tool described in this report.

2.1.1 Interventions used in the Real Options Tool

The general approach followed in RO tool is that a strategy will be based on a series of up to 3 triggered interventions aiming to provide sufficient network capacity in network post-fault or maintenance outages. The default process involves no action until a trigger is met for the next intervention. Two types of interventions can be scheduled within an examined planning horizon, which are:

- The traditional network reinforcement intervention; and,
- the post-fault C_2C DSR intervention.

The traditional network reinforcements (e.g., installation of new transformers in existing substations) will be assigned with a commitment timescale, which accounts for the implementation lead time (e.g., 3 years needed to increase the network capacity). It is expected that the cost of implementations would be spread over the reinforcement lead time.

The DSR interventions are post-fault C_2C cases with customer load disconnected by the DNO. This will be based on an annual payment with no call-off charges. The contracts would generally allow 8 continuous hours off supply, repeated for as many days as required and with no protected days. However ideally in the longer term, the RO tool should be also be capable of handling other types of DSR or innovative methods of providing capacity.

Some of the key differences of post-fault C_2C DSR to the traditional solutions are that:
the DSR capacity contracted can vary by year as demand alters and more or fewer customers are contracted (based on the difference between forecast demand and the trigger level) in contrast to a traditional intervention delivering a fixed amount of extra capacity;
the total DSR capacity that customers are willing to contract can be uncertain;
the cost profile of implementing DSR involves a combination of initial and recurring costs, based on customer type and MVA contracted.

2.1.2 Overview of the Real Options Tool by function

The aim of this report is to provide the RO tool user with a better understanding of the tool inputs, computational processes and outputs. Although the detailed theory behind the developed multi-layered approach of the RO modelling [2] is not within the scope of this report, the methodology behind the different calculations of the RO tool is described.

The RO tool consists of the following 7 main computational modules, which are:

1. The Probabilistic Forecasting Module;
2. the Initial Excess Load Module;
3. the Intervention Scheduling Module;
4. the Cost Assessment Module;
5. the Residual Excess Load Module,
6. the Losses Module; and,
7. the Cost Summary Module.

The following subsections present in detail the above mentioned computational modules of the tool.

2.1.3 Overview of the Real Options Tool by worksheet tab

The RO tool consists of the following worksheet tabs.

- User notes (see section 3 for recommendations on how to use the model);
- Input tabs (green)
- Site Inputs, including demand scenarios, initial losses and initial capacity.
- Strategy A inputs
- Strategy B inputs
- Scenario Summary – note this does not update automatically, but is updated using the macro on the 'Finance Inputs and Summary tab'
- Finance Inputs and Summary – presenting financial inputs, and quickly presenting the most relevant output data on the residual excess load, and a summary of net present costs for different financial inputs.
- Other output tabs
- Capacity Charts
- Timescales and Cashflows
- DNO cost distribution
- Least regret analysis
- Calculation tabs (not intended for review, except by expert users making changes to the function of the model)
- Strategy A Calcs
- Strategy A subtables
- Strategy B Calcs
- Strategy B subtables
- Losses calcs.

2.2 Probabilistic Forecasting Module

The Probabilistic Forecasting Module (PFM) aims to incorporate demand forecasting uncertainty in the decision making process. As shown in Fig. 1, the tool user needs to enter three inputs in PFM, which are:

- The demand forecasting scenario results (i.e., the Electricity North West peak scenarios of Best View, Active Economy, Green Ambition and Focus on Efficiency scenarios) and the corresponding time horizon;
- a volatility value; and,
- a weather-related volatility (i.e., weather uncertainty volatility).

It should be noted that:

- the RO tool can be used for a forecasting time horizon up to 45 years (eg 2015 to 2061 or 2016 to 2062). As the current version of demand scenarios only extend to 2031, a simplifying assumption is made to extend all scenarios from 2031 to 2062 – either at their 2031 value or continuing the increment in demand between 2030 and 2031 in the best-view demand scenario
- the weather-related volatility in peak demand values can be defined by the standard-deviation of the history of National Grid's ACS corrections for Great Britain;
- the non-weather volatility value concerns all other uncertainties affecting demand, and a reasonable interim value has been suggested but a methodology for this value based needs to be defined, based on the historic variation in historic peaks.

Having entered the demand forecasting scenario results, the forecasting time horizon and the volatilities per scenario, the RO tool is in position to produce 100 probabilistic variations of demand forecasting per scenario per year. In order to do this, the RO tool first automatically produces per year random Monte Carlo numbers from 0 to 1 considering the user-defined demand forecasting horizon. It should be noted that:

- 1 of the 100 probabilistic variations, run 2, is forced to acquire zero values for all years of the forecasting horizon examined; and,
- the calculated Monte Carlo numbers are the same for all scenarios.

Next, the inverse normal cumulative distribution is used considering the volatility values (i.e., general non-weather volatility and weather related) per scenario to calculate the corresponding cumulative noise for the 100 probabilistic variations per year. The derived cumulative noise (i.e., 100 variations x Years per scenario) are then summed with the demand forecasting scenario results to produce the PFM output.

It should be noted that there are two different PFM outputs, depending on whether the weather volatility is considered or not. Each of these two PFM outputs consists of 100 probabilistic variations of demand forecasting per scenario per year. The probabilistic variations that do not consider weather volatility can be then used (i.e., sequentially) as one of the inputs of the Initial Excess Load Module, which is presented in subsection 2.3.

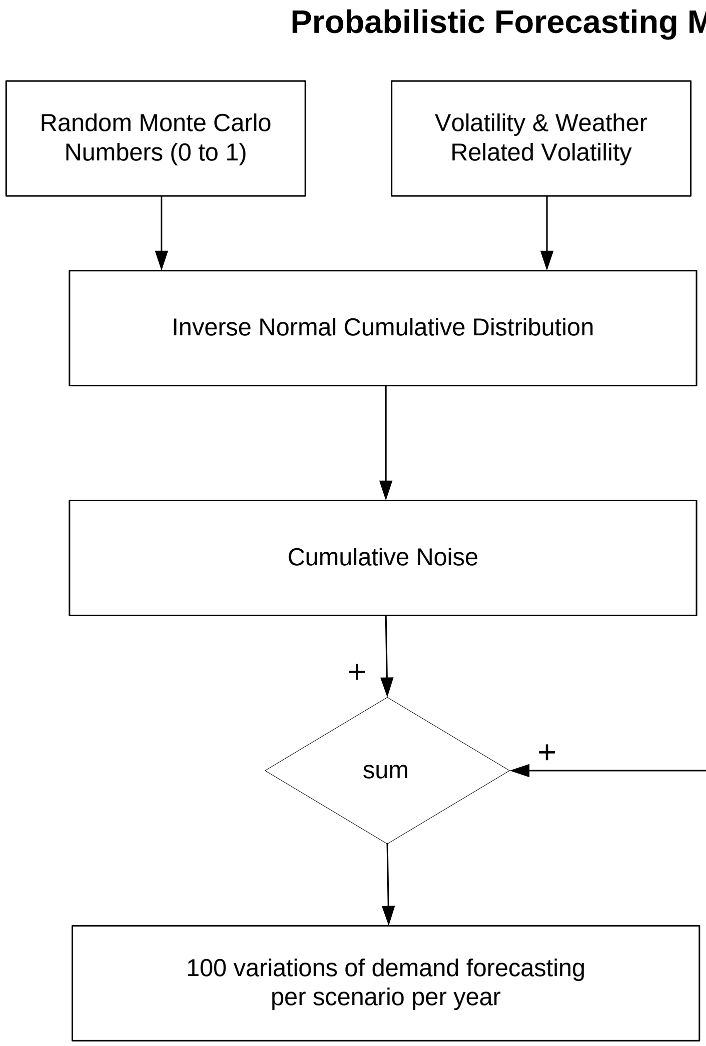

Fig. 1. **The Probabilistic Forecasting Module of the Real Option Sep 15 v.2.1 tool.**

2.3 Initial Excess Load Module

The Initial Excess Load Module (IELM) uses the PFM output as one of its three inputs, as shown in Fig. 2. The other two inputs of the IELM are:

- the user defined initial firm capacity of the examined substation; and,
- the incremental components of the best view scenario.

According to the C_2C concept [1] and ER P2/6, the initial firm capacity corresponds to the available post-fault MVA headroom (i.e., combination of remaining asset-related capacity and/or automatic transfer capacity from other circuits after one network outage or maintenance/operational event). .

The incremental components are equal to the difference in the forecasted demand between two consecutive years (i.e., equal to $\Delta P_{forecasted}/\Delta t$ where Δt = 1 year). In practice, the incremental components show the per year changes, in terms of increase or decline, of the forecasted demand according to the best view scenario.

The output of the IELM is the initial excess load (L) values per scenario per year. The initial excess load values derive from simply exporting the initial firm capacity from the summation of the incremental components and the PFM output (i.e., ENWL scenario results with “probabilistic noise”). It should be noted that the PFM output considered in the IELM only considers the non-weather related volatility.

In practice, positive initial excess load values correspond to the extra capacity in MVA needed to be added to the examined substation for every scenario and for every year within the examined forecasting horizon. Consequently, any derived positive values of the initial excess load trigger requirements for the deployment of one or more interventions.

The initial excess load (IELM output) can trigger the commitment to an intervention, which is described in more detail in the following subsection 2.4. Nonetheless, it should be highlighted that although the trigger level could equal firm capacity or a P2/6 N-1 condition or a P2/6 N-2 condition or reaching LI5, the rationale for the trigger level is at the discretion of the planning engineer.

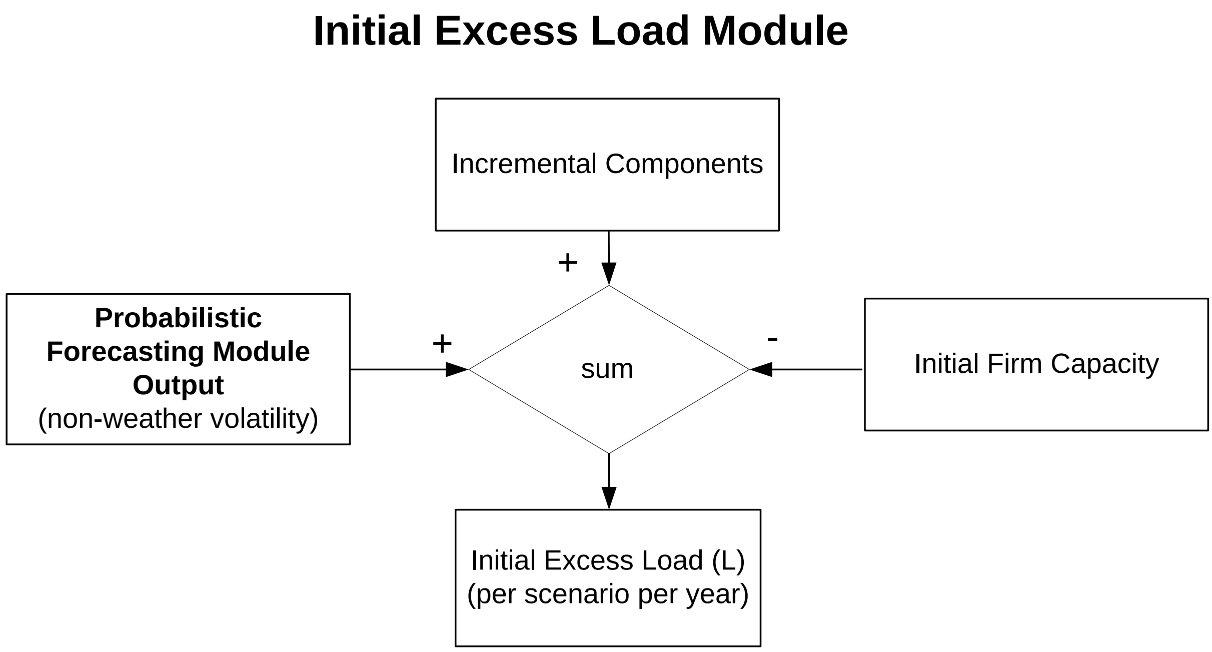

Fig. 2. The Initial Excess Load Module of the Real Option tool.

2.4 Intervention Scheduling Module

The Intervention Scheduling Module (ISM) is responsible for defining the time instants (i.e., years) within the examined forecasting horizon when user-defined interventions (i.e., technical solutions) should be implemented. As shown in Fig. 3, the ISM uses the IELM output (i.e., the initial excess load values) as one of its inputs. The other input is the user-defined strategy. When the initial excess load value becomes positive, or a specified year is reached, this is the trigger to commit to the intervention.

The Real Options tool allows the investigation of two user-defined Strategies of up to 3 interventions. Each intervention is set as ‘Demand Response’, ‘Invest in Asset’ or ‘Do Nothing’, with the ‘Demand Response’ based on the post-fault demand response method with existing demand customers developed in 0. Strategies A and B are set up equivalently in the RO tool, but Strategy A is normally used for the traditional strategy and Strategy B for the smart strategy. The model could however be used to compare two DSR strategies or two traditional reinforcement strategies, or (most usually) a traditional strategy with one combining DSR and traditional reinforcement.

The ISM computations are implemented in exactly the same way for Strategies A and B. As shown in Fig. 3, the ISM considers from the user-defined Strategies A and B:

- The corresponding capacities C_i in MVA of interventions i=1 to 3 (i.e., extra capacity that can be added to the examined substation with every intervention);
- the total number N_i of DSR customers / network reinforcements of interventions i=1 to 3 (N_i=1 for the traditional network reinforcement interventions);
- the lead time in years S_i of every intervention; and,
- the end year E_i of every intervention.

Fig. 3 shows the Intervention Scheduling Module of the RO tool. The iterative process presented here for one scenario is applied independently for every scenario for each of Strategies A and B.

The actual aim of ISM is to produce for every scenario a group of three matrices (i.e.,matrix dimensions = probabilistic variations x years), where each matrix is associated with an intervention of Strategy A or B. These matrices contain as elements the intervention indices I_i for interventions i=1 to 3.

Intervention indices can get zero or positive integer numbers. Zero values practically mean that the corresponding intervention has not been scheduled within the associated probabilistic variation and year. On the contrary, the positive integer values correspond to the number of DSR customers / network reinforcements scheduled within the associated variation and year. It should be noted that for the case of scheduled network reinforcement interventions, the corresponding indices can be only set equal to one (i.e., I_i=1).

The ISM computations in Fig. 3 are carried out with the following steps:

<u>Step 1</u>: The process starts considering as inputs the current year (i.e., y=0 accounts for year 2015) and the initial excess load (L) values in MVA (IELM output). If in year y=0 there is no excess load, i.e. L<0, then no intervention is needed (i.e., $I_1=I_2=I_3=0$). In this case the year index increases by 1 (i.e., y=y+1) and the process re-iterates from the same step (step 1). Otherwise, the process continues with step 2.

<u>Step 2</u>: If the examined year is within a future time horizon that is shorter than the lead time of Intervention 1 (i.e., $y<S_1$) then Intervention 1 is selected from year S_1 until year S_1+E_1. Otherwise, Intervention 1 is selected from year y until year $y+E_1$. The process continues with step 3.

<u>Step 3</u>: If the initial excess load does not exceed the total extra capacity by all DSR customers or traditional network reinforcements of intervention 1 (i.e., $L<N_1{\cdot}C_1$) then the intervention index is set equal to the number of n_1 DSR customers/network reinforcements of Intervention 1 that can cover the initial excess load (i.e., $I_1=n_1$ where $n_1{\cdot}C_1 \geq L$). Next, the year index increases by 1 (i.e., y=y+1) and the process re-iterates from step 1. Otherwise, N_1 number of DSR customers / network reinforcements that provide a total extra capacity of $N_1{\cdot}C_1$ are selected (i.e., intervention index setting: $I_1=N_1$). The process continues with step 4. (Note: $N_i = n_i = 1$ for the traditional network reinforcement interventions)

<u>Step 4</u>: If the examined year is within a future time horizon that is shorter than the lead time of Intervention 2 (i.e., $y<S_2$) then Intervention 2 is selected from year E_2 until year S_2+E_2. Otherwise, Intervention 2 is selected from year y until $y+E_2$. The process continues with step 5.

<u>Step 5</u>: If the excess load after the deployment of Intervention 1 can be covered by Intervention 2 (i.e., $L-N_1\ C_1<C_2$) then the intervention index is set equal to the n_2 number of DSR customers/network reinforcements of Intervention 2 that can cover the capacity needed (i.e., $I_2=n_2$ where $n_2{\cdot}C_2 \geq L-N_1{\cdot}C_1$). Next, the year index increases by 1 (i.e., y=y+1) and the process re-iterates from step 1. Otherwise, N_2 number of DSR customers / network reinforcements that provide a total extra capacity of $N_2{\cdot}C_2$ are selected (i.e., intervention index setting: $I_2=N_2$). The process continues with step 6.

<u>Step 6</u>: If the examined year is within a future time horizon that is shorter than the starting time of Intervention 3 (i.e., $y<S_3$) then Intervention 3 is selected from year S_3 until year S_3+E_3. Otherwise, Intervention 3 is selected from year y until $y+E_2$. The process continues with step 7.

<u>Step 7</u>: The intervention index is set equal to the n_3 number of DSR customers/network reinforcements of Intervention 3 that can cover the capacity needed (i.e., $I_3=n_3$ where $n_3{\cdot}C_3 \geq$

$L-N_1 \cdot C_1-N_2 \cdot C_2$). The year index increases by 1 (i.e., y=y+1) and the process re-iterates from step 1.

Following steps 1 to 7, the output of the ISM is a total number of 30 intervention matrices (5 scenarios x 2 strategies x 3 interventions), where the elements I_i of these matrices correspond to a given probabilistic variation and year within the examined forecasting horizon.

It should be noted that for both Strategies A and B it is the responsibility of the Real Option tool user to define Interventions 1 to 3 that can provide sufficient extra capacity to the examined substation taking into account the demand forecasting results. This can be sense-checked by reviewing the capacity graphs (i.e., in the “Capacity Charts” Excel tab of the RO tool). Having scheduled the Interventions 1 to 3 from year 0 (i.e., 2015) to the end of the examined forecasting horizon, the next stage is to assess the associated net present costs.

Intervention Scheduling Module

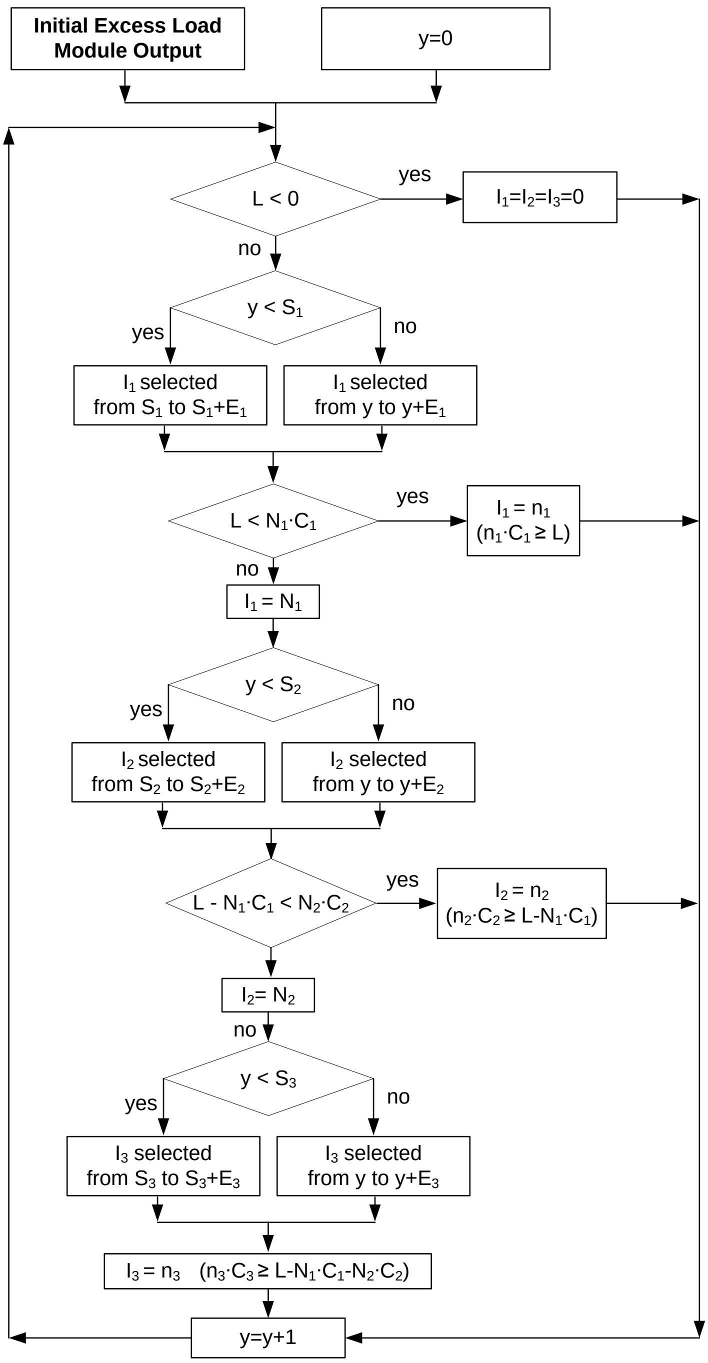

Fig. 3. The Intervention Scheduling Module of the Real Option tool.

2.5 Cost Assessment Module

The total weighted Net Present Costs (NPC) for each of Strategies A and B are estimated using the Cost Assessment Module (CAM), as shown in Fig. 4. The CAM inputs are:
The output of the Intervention Scheduling Module - ISM (i.e., the 30 intervention matrices);
the associated cost data for every Intervention of Strategies A and B.

The cost data input that is related with the DSR and network reinforcement Interventions of Strategies A and B is user-defined. More specifically, the user needs to define:
for DSR interventions: the initial cost and ongoing per year costs; and,
for traditional network reinforcement interventions: the spread of costs within a 5 years horizon.

More specifically, regarding the post-fault C_2C DSR interventions, the associated user-defined costs in the RO tool are:

- the DSR buy price £/MVA/year,
- the initial automation costs:
- £ per automation point on network,
- £ per customer depending on customer type, and,
- the annual management and billing costs £/year/contracted customer.

As shown in Fig. 4, the CAM process starts with the cost assessments (i.e., cash flows) for every year. More specifically, the intervention matrices (i.e., ISM outputs) are multiplied with the associated user-defined cost data.

This cost assessment process results in 30 cost matrices (i.e., 5 scenarios x 2 strategies x 3 interventions, where matrix dimension=100 probabilistic variations x years). Next, the CAM sums all cost matrices that belong to the same scenario and strategy. The derived matrices are the future cost values (i.e., cash flows) from which the net present cost values can be calculated. It should be noted that the calculations of the net present cost values are carried out using the user-defined total discount rate.

Having assessed the net present cost values, the user-defined weighting factors per scenario are then used to assess the total weighted net present cost, which is the output of the CAM. More specifically, the CAM output is a group of two vectors, each corresponding to 100 probabilistic variations of Strategy A or B.

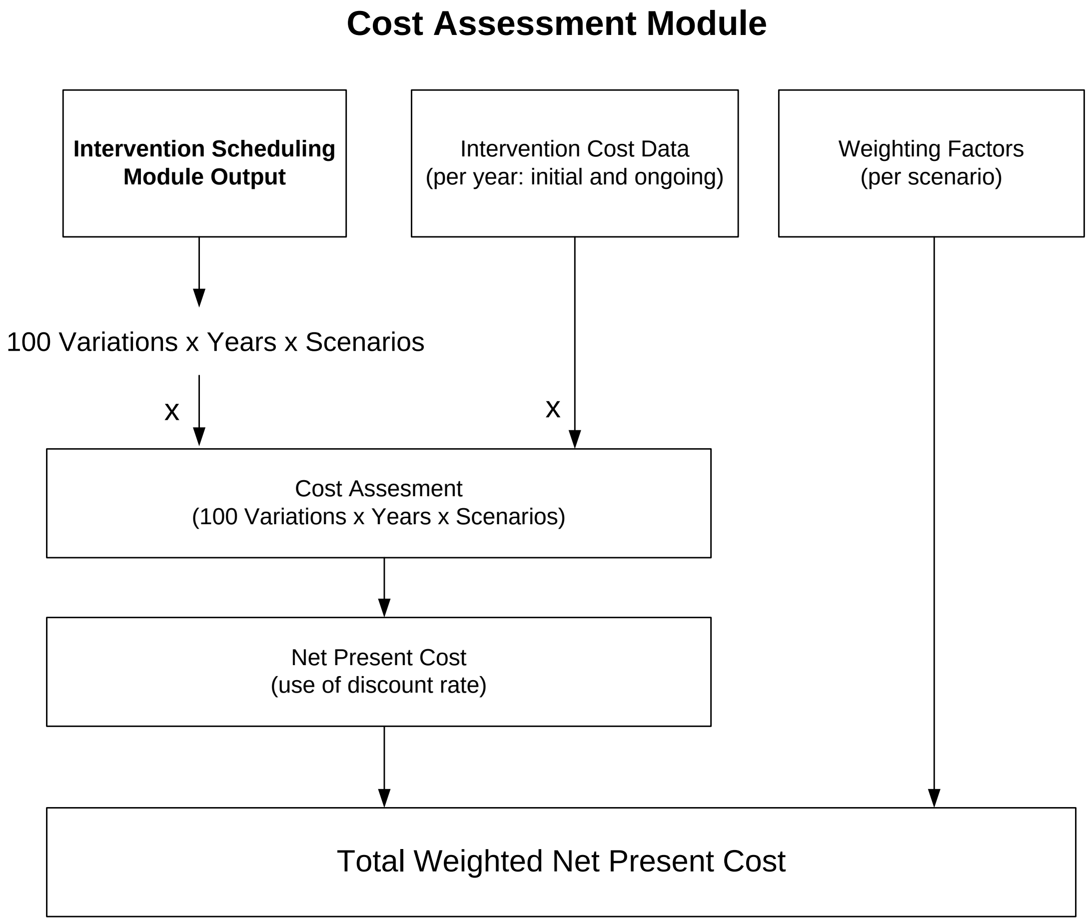

Fig. 4. The Cost Assessment Module of the Real Option tool.

Having obtained the total weighted net present cost results from CAM (i.e., vector outputs per strategy), other metrics associated with cost risks can be then assessed by the RO tool. More specifically, the RO tool uses the output of the CAM to then assess:
The Value at Risk (VaR) for the top 5 and 10% values of the CAM outputs; and,
the Conditional Value at Risk (CVaR).

The VaR indicates a boundary between normal and high costs, where 10% VaR means that only 10% of the cost values (i.e., CAM output vectors per strategy) are higher to VaR. A 10% CVaR corresponds to the average of the 10% of cost values (i.e., CAM output vectors per strategy).

2.6 Residual Excess Load Module (RELM)

Unlike the IELM (see subsection 2.3) that is used to assess the initial excess load, the Residual Excess Load Module (RELM) can provide a metric of the associated operational risks (i.e., technical risks) from the deployment of a strategy that involves post-fault C_2C DSR or network reinforcement interventions. Fig. 5 shows the RELM, which uses as inputs:

- Input 1: The output of the ISM (i.e., the I_i values for i=1 to 3 interventions) considering the 100 variations that take into account the non-weather related volatility;
- Input 2: the user-defined capacities per intervention (i.e., C_i) for the examined strategy;
- Input 3: the user-defined initial firm capacity in MVA of the examined substation; and,
- Input 4 (bottom of Fig. 5): the output of the Probabilistic Forecasting Module considering the weather related volatility.

The inputs 1 and 2 are first multiplied to obtain the extra capacity that is added to the examined substation from the deployment of the scheduled interventions. Next, this extra capacity is added to the initial firm capacity (input 3) to derive the total network capacity of the examined substations. The subtraction of input 4 (i.e., forecasted demand per scenario) from the total network capacity corresponds to the residual excess load, which is the output of the RELM.

The RELM output is plotted in the “Cost and risk distributions” tab of the RO tool Excel file by means of distribution box plots along the examined planning horizon. This output practically shows on a year-per-year basis the extent that the weather volatility (i.e., weather associated uncertainties) or the lead time of different interventions can increase the technical risks (i.e., less network capacity than needed).

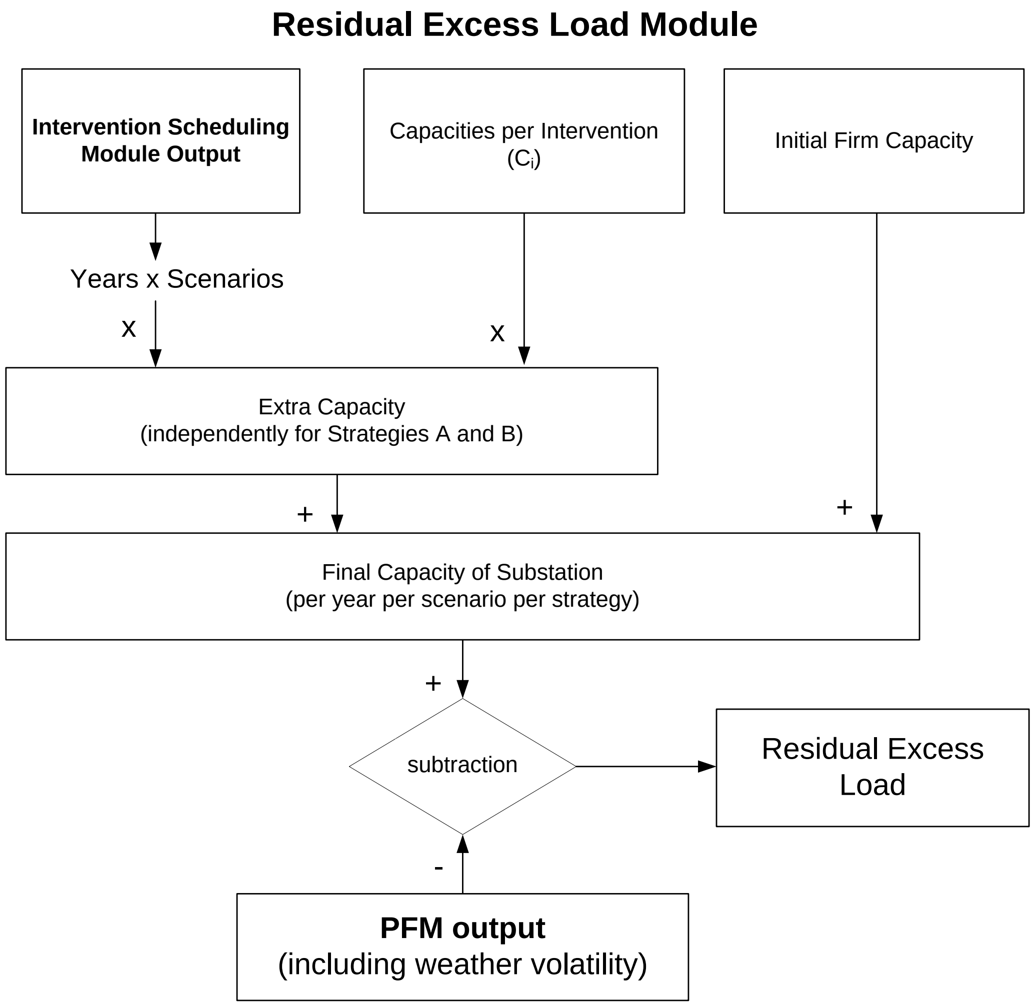

Fig. 5. The Residual Excess Load Module of the Real Options tool.

2.7 Losses Calculations

Approximate losses calculations are made for each of the five macro-scenarios, but have not been extended to 100 Monte Carlo variations.

The initial inputs to the model are
- fixed losses in MW
- resistive peak losses in MW in the last year
- the observed peak MVA load at which the peak losses were calculated, and
- a loss load factor.

The peak losses in the last year are the sum of the fixed losses and resistive peak losses. The annual losses in the last year are thus [peak losses] x [loss load factor] x 8760 hours to indicate annual losses in MWh.

As loading level changes, the resistive losses are then assumed to increase as the square of the peak load, with no change in loss load factor. So for peak losses initially calculated at a peak load of A, the annual losses for an observed peak load of B would be:

$$8760 \times \left(\left((historic\ resistive\ peak\ losses) \times (loss\ load\ factor) \times \left(\frac{B}{A}\right)^2 \right) + (fixed\ losses) \right).$$

The model then values each MWh of losses at the values defined by Ofgem's RIIO-ED1 Cost Benefit Analysis template (v4 January 2014) [3] – mirroring the assumptions in that model for discount factor, wholesale value of loss, grid carbon associated with losses and the cost of carbon.

Note that A is an historic *observed* peak load and B is a forecast *observed* peak load. The demand scenarios are however true peak demand – thus B is created be adjusting the forecast true peak load downwards based on the latent demand contribution at peak (from generation). In the current version of the model, this is done based on the difference between true and observed peak in the base year, but in future the model might be based on scenarios of how latent demand (generation output) would change over time.

2.8 Cost Summary modules

Using Excel's What-if Analysis and Scenario Manager on the 'Finance Inputs and Summary' tab, the following inputs can be easily adjusted to either show a simple analysis of DNO cash flows (currently called the Commercial View, but a DNO's actual commercial view may be more sophisticated than this) or a more sophisticated view which approximates the customer view as represented in Ofgem's RIIO-ED1 Cost Benefit Analysis template.

The change between these views is made by altering just four inputs:

- number of years considered
- discount rate
- the Information Quality Incentive (IQI) sharing factor – currently 58% in the commercial view but not applied in the Regulatory view (100%)
- whether regulatory factors included – yes/no – to include losses and an uplift to increase all DNO costs to take account of the cost of financing the asset base based on the Weighted Average Cost of Capital, capitalisation percentage, depreciation lifetime and discount rates as specified in Ofgem's RIIO-ED1 Cost Benefit Analysis template.

Buttons linked to macros are provided to automatically switch between these views.

A full justification of these inputs is not provided here, but the outputs are then for example an assessment of DNO cost and losses cost, per strategy and for all five scenarios and the mean across all scenarios.

3 PROPOSED USE OF THE REAL OPTIONS TOOL

The RO tool helps its user in supporting a network planning decision between two different strategies, i.e. using post-fault C_2C DSR interventions versus traditional network reinforcements. This section first describes the suggested approach in using the RO tool together with other outside to this tool processes to support a decision for a strategy over another. Next, it discusses the RO tool advantage to a) support beneficial strategies and b) provide better insights for a multi-objective decision from a network planning perspective.

Specifically, the user of the RO tool proceeds with the following steps:
Step 1: Set up inputs and review whether the capacity charts of the “best-view” scenario and associated timescales are sensible in relation to demand scenarios and strategies.
Step 2: Check whether the residual excess load (see subsection 2.6) is acceptable in both strategies examined within the planning horizon and if not amend the intervention strategies.
Step 3: Compare the strategies based on commercial perspective on costs (i.e., use DNO-defined discount rate).
Step 4: Compare the strategies based on customer perspective on costs (i.e., use Ofgem’s suggested discount rate), and includes losses. using the Ofgem Cost Benefit Analysis (CBA) framework.
Step 5: Make business-decision based on multiple criteria, and also potentially outputs outside of the model

Step 1
The user updates the blue cells on 'Site inputs', 'Strategy A inputs' and 'Strategy B inputs' for the project, using default values where appropriate

The first step in using the RO tool suggests that the user should mainly consider sensible interventions in terms of the extra capacity in MVA that can be added to the examined substation. For example, if demand forecasting suggests 10 to 15MW future load when the initial firm capacity is only 5MW, the DSR and traditional network reinforcements should provide a 5 to 10MW extra capacity to the examined substation. This sense-check and the associated timescales are recommended to be done for the “best-view” scenario. This step helps identify any input errors e.g. an intervention related to a previous project which has not been overwritten.

Step 2
The residual excess loads (output of RELM / see subsection 2.6) practically shows on a year-per-year basis the extent that the weather volatility (i.e., weather associated uncertainties) or the lead time of different interventions can increase the technical risks (i.e., less network capacity than needed).

Step 2 suggests that, having entered all RO tool inputs in step 1, the calculated residual excess loads (i.e., distribution box plots along the examined planning horizon / “Cost and risk distributions” Excel-tab of the RO tool) should be sense-checked. If the assessed residual excess load values are not reasonable, then the user should amend the intervention strategies by increasing the extra capacity that each intervention can add on the examined substation.

Step 3
Similarly to most net present cost assessment approaches used to compare different investment options, the adoption of representative and realistic discount rates and planning horizons can be the most critical components. Within the context of the ENWL (or other UK DNO) business, the RO tool should be able to support the decision to implement a strategy based on the commercial perspective of costs.

Therefore, a DNO-defined discount rate (e.g., 5 to 15% discount rate) considering commercial aspects should be used in a reasonable from a commercial perspective horizon (e.g., 15 years horizon) to compare the net present costs of the examined strategies.

Step 4
Ofgem's CBA aims in assessing net present costs of examined planning interventions based on a customer perspective of costs. Thus, step 4 suggests the use of the CBA's discount rate (i.e., 3.5%), a 45 future years planning horizon (i.e., 45 years of life expectancy of assets), the value of losses (wholesale and carbon), and the financing costs of a depreciating regulatory asset base.

Step 5
The final step of the analysis is to review the combined outputs of the model – the network risk distributions, the commercial cost distributions and the regulatory cost distributions – to inform an acceptable business decision regarding strategies involving post-fault C_2C DSR interventions or traditional network reinforcements..

From a decision making perspective, the investigation between two strategies with acceptable residual excess loads (step 2 / subsection 3.1) can lead to two different outcomes.

Case #1: One Strategy is lower in net present cost in all demand scenarios and in both the commercial and regulatory perspectives. The choice of preferred strategy is thus clear, but it may be that the case is more compelling from either the commercial or regulatory perspective.

Case #2: The least-cost strategy differs according to the demand scenario and cost perspective. As a minimum condition to justify a strategy as efficient to Ofgem, the chosen strategy should have least cost in the best-view scenario and regulatory perspective. However it should be noted that in such cases the network planner needs further information so as to define the preferable strategy. This fact highlights the significance of using the RO tool to follow a multi-objective rather than a single objective approach in decision making. More specifically, the RO tool-user can in such cases be aware of:
Spread of costs (cash flows) between different strategies;
distribution of risks within the planning horizon (i.e., residual excess loads);
costs based on commercial and customer perspectives; and,
costs depending on different potential demand forecasting scenarios.

4 REVIEW OF THE REAL OPTIONS TOOL

This section aims in allowing a better insight in the capabilities, limitations and modelling aspects of the Real Options tool. In the following subsections, first the advantages and disadvantages of the spreadsheet modelling approach of the RO tool are discussed. Next, the tool limitations are presented with respect to the incorporation of energy losses, network reliability aspects and planning horizon.

4.1 Implementation using Spreadsheet Modelling

The Real Options model [2] is an industrially-oriented methodology that considers realistic DSR and traditional network reinforcement options to support corresponding network planning decisions. This methodology is implemented using spreadsheet calculations in the Real Options tool. The advantages and disadvantages of this spreadsheet modelling are discussed in the following subsections. It should be noted that this subsection does not necessarily focus on comparing spreadsheet modelling with script-based approaches, but mainly focuses on the particular spreadsheet modelling approach of the RO tool.

The RO spreadsheet tool calculates quickly, is user-friendly for experienced Excel users, and can be updated by any Excel expert (without particular programming skills). It allows the flexibility of comparing strategies with up 3 interventions. The model can be rerun with additional strategies if more combinations need to be considered.

The disadvantages of the model are its large size (34 Mb), that outputs (i.e., diagrams and tables) appear in different spreadsheet tabs (many of them duplicated), and can be difficult to adapt the functionality of the tool (i.e., computational modules spread across multiple cells and tabs).

4.2 Next steps in development

The RO modelling approach exhibits several significant advantages over Strategic Planning's current methods for comparing investment options for delivering capacity on the Grid and Primary network. These include the way it handles demand uncertainties and the scheduling of realistic interventions in a way which would be prioritised by DNOs.

Nonetheless, further improvements can be made to enhance its use in supporting network planning decisions. This subsection describes aspects not currently taken into account in the current RO tool in order to highlight suggestions for the tool improvement.

4.2.1 Testing and sensitivity analysis

So far informal testing and sense checks of results have occurred as part of the development of case studies and sensitivity analysis. This testing has been the key driver of the model development since the initial July 2014 version of the model was produced by the University of Manchester. To some extent this approach can continue as it focuses on the model as used.

However a more thorough testing regime – including a range of case studies and sensitivities – may need to be considered to give confidence in the future use of the model.

4.2.2 Documentation of approach / assumptions

This document is the first step, but there are a number of specific areas to address.

Description of the DSR inputs and assumptions.
The cost of the implementing the C_2C method is based on initial set-up costs plus ongoing annual costs, with no additional costs based on fault events. The length of the C_2C contract is a variable from 3-5 years, so if demand falls, the contract need not be renewed after the

end of the minimum period. However if capacity is still required, it is assumed that the contract can be renewed. These assumptions all need to be clearly documented to allow future update.
The model allows a one-year leadtime between commitment and implementation (shown as a variable in the model, but the model fails if an alternative value used, so a one-year leadtime is currently an assumption).
Model structure - The analysis of the need for C_2C DSR in terms of number of customers required is done in the 'subtable' tabs, while the implementation of the contract period is done in the tables.
The Timescales tab also needs to be checked for errors and consistency, as does the description of DSR inputs.
The model needs to be tested in the case of defining the year of an intervention, as opposed to a trigger based on the loading.
The Capacity Charts need to automatically update to the timescale of the analysis.

4.2.3 Clarify approach to annual update and price base

Each year, revised demand scenarios will be available from Strategic Planning, with a new base year. There may also need to be an update of price base ie applying an appropriate inflation factor to the losses and carbon inputs. Other inputs such as volatility measures will also require periodic review.

4.2.4 Extension of the losses analysis to 2nd and 3rd interventions

Currently the losses effects of the 1st traditional intervention can be calculated by the model – this needs to be extended to included inputs and calculations for the 2nd and 3rd interventions.

4.2.5 Amendment to match the cost treatment in the Ofgem CBA model

The approach in the model is largely consistent with Ofgem's RIIO ED1 CBA approach [3], with some deviation in discount rate assumed after 2046 (3.5% rather than 3%), losses costs truncated to 2062 rather than 2067, and the full cost of DNO investment considered rather than truncated to 2067.

The reason for these differences in practicality in implementation without vastly increasing the complexity and size of the real options model.

These differences in long-term cost assumptions are minor and not considered likely to affect any decisions assessed by the tool – however this difference needs to be quantified and confirmed.

By adding additional rows to the model to extend it to 2067, and changing the form of the NPV calculation from using Excel's NPV formula to a 'sumproduct' of costs in each year with a discount rate and financing factor based on Ofgem's CBA, it is expected that the RO model can be converted to present a cost view matching the Ofgem RIIO-ED1 CBA model.

In particular, we may wish to adapt the model to provide all outputs in a 12-13 price base, for comparability across the whole programme.

4.2.6 Check sufficiency of the 'DNO cash flow' view for commercial assessment

The DNO cash flow currently considers DNO costs to 2031 at a specified discount rate. This does not make any adjustment for the IQI sharing factor in the ED1 period, or any other tax or financing effects. Commercial colleagues may wish further analysis of the impact on the business to be performed, either within the model or outside. DNO cash flows per scenario can be easily extracted from the model if such analysis is required.

4.2.7 Assess cost impact of Network Reliability

The assessment of network reliability can define the probability that the different parts of a distribution network will perform a required operation for an examined time interval. The current RO tool version does not take into account cost impacts of network reliability. Consequently, as far as future versions of the RO tool are concerned, network reliability should be associated in them with the effects of the DSR and traditional network reinforcement interventions on magnitude, duration and location of potential shortage events.

For example, DSR interventions are in the current tool version considered to be able to support network capacity with the contracted MVA. Nonetheless, in practice the DSR customers could potentially not be in position to be fully in line with the contracted MVA capacity.

It may be possible to adapt the excess load metric to indicate an additional cost risk associated with reliability in the two strategies.

4.2.8 Model testing – additional case studies and sensitivity analysis

The model has only been applied to a small number of case studies so far, so although there has been a lot of review and sense-checking of outputs, it cannot be considered to be fully tested. Equally the relative criticality of inputs to the model has not been assessed.

4.2.9 Additional user guidance, and decision on transition of prototype to BAU

Beyond this document, there is limited user guidance for the model. When the prototype is complete, analysis will be performed as to whether the proptotype is appropriate as a BAU tool within Electricity North West or more generally, and what additional changes to the model, documentation or training are required.

5 CONCLUDING REMARKS

In this report, the latest available Real Options tool is described using a structure of computational modules, in order to allow a better insight into the corresponding numerical processes and methodologies. More specifically, the tool processes are explained by means of computational modules. In order to show how the user-defined inputs are used to provide cost- and risk-related results, flowcharts are presented and practical insights are described for every computational module. The RO tool follows a spreadsheet modelling approach, thus the algorithmic/flowchart-based description of its computational modules allow a potential script-based development of a future RO tool.

This document recommends an approach to using the RO tool to compare strategies involving post-fault C_2C DSR interventions versus traditional network. The suggested approach suggests that cost assessment using the RO tool are based both on commercial and customer (i.e., societal benefits) perspectives. Additionally, effects of the reduction in energy losses and the depreciation of assets are taken into account in cost assessments in line with Ofgem's Cost Benefit Analysis.

Following the proposed use of the RO tool, the network planner can identify cases where one strategy exhibits profound advantages over its alternatives. The assessment of net present cost in this case can be the dominant objective in the decision making process. Nonetheless, it should be noted that in the confusing cases where no strategy exhibits consistent benefits to its alternatives, network planner can use the RO tool within the context of the recommended analysis to follow a multi-objective rather than a single objective approach in decision making.

The advantages and disadvantages of the latest version of the RO tool are also discussed. In general, the RO tool advantages include the negligible computational cost and the easy use from experienced Excel users. On the contrary, the tool disadvantages mainly concern the complexity regarding its outputs and the difficulty in updating the tool due to the spreadsheet-based modelling.

Although the RO tool exhibits several significant advantages (including the scheduling of realistic DNO-defined interventions), there should be a continuous focus on potential tool improvements considering not only its limitations, but also forthcoming technical challenges. Thus, suggestions for the RO tool improvement are also presented in this report, mainly focusing on the incorporation of energy losses, depreciation of assets, network reliability issues and expanding the demand forecasting horizon.

6 REFERENCES

[1] Electricity North West, “Capacity to Customers Second Tier LCN Fund Project Closedown Report”, 26 June 2015.

[2] P. Mancarella, J. Moriarty, "Flexible investment strategies in distribution networks with DSR: Real Options modelling and tool architecture", 2013.

[3] Ofgem, “RIIO-ED1 Cost Benefit Analysis guidance note 17 Jan 2014”, 2014.