INCORPORATING ASSET MANAGEMENT INTO POWER SYSTEM OPERATIONS

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ABSTRACT

Generally, decisions regarding power system operations are based only on operational parameters of the distribution network (DN) such as voltages, currents and power flows. Asset condition is a key parameter that is usually not considered by Network Management Systems (NMS) in their optimization process. Against this background, this paper seeks to indicate that the condition of power system assets can influence the network operation decisions. The criteria used to decide the optimal network operation are asset condition-based risk and losses. This is illustrated by a case study, where a number of network reconfigurations are examined in a representative DN and the results show that by taking asset condition information into account, then an improved operation of the network can be achieved.

INTRODUCTION

The privatization of the UK electrical power industry and ageing equipment in distribution networks (DNs) requires Distribution Network Operators (DNOs) to continually consider new and innovative approaches to the management of their assets. This requires the utility companies to find an optimum balance between their expenditure and quality of supply. Maintaining this balance is becoming increasingly difficult due to the proliferation of renewables-based distributed generation (DG) with their associated power output variability, evolving loads such as electric vehicles and heat pumps and the increasingly old power system components [1, 2].
Current practice is that power system operations and asset management (AM) activities do not take each other into account. However, the proliferation of smart grid technologies such as active network management, online condition monitoring (CM) and AM decision support tools and methodologies, such as the DNO Common Network Asset Indices Methodology (CNAIM) [3] and RCAM Dynamic® [4], will provide DNOs with opportunities to bring network operations and AM activities together by integrating these technologies.
This paper demonstrates how these two activities can be integrated in order to achieve an improved outcome from a cost and risk point of view. This is achieved by making decisions for network operations, which take account of not only the operational parameters of the DN, but also the condition of the assets, through their corresponding Health Indices (HIs). This concept is illustrated diagrammatically in Fig. 1.

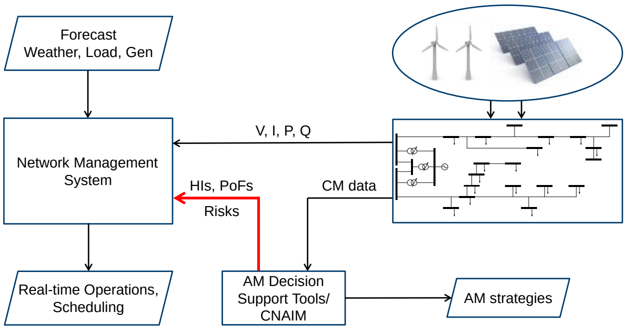

Figure 1: Integrated Asset Management and Network Operation Concept

Typical national fault statistics for the UK are shown in Table 1, which contains the proportions of the total number of incidents, of customer interruptions (CIs) and of customer minutes lost (CMLs), by voltage level. The Office of Gas and Electricity Markets (Ofgem) rewards or penalizes DNOs according to their performance with respect to the aforementioned metrics [5]. These measures result in the DNOs concentrating their efforts on improving performance in these indices, particularly at Medium Voltage (MV) level. The conventional approach to improving fault performance in a DN would be reinforcement and asset replacement, which can be very costly. Leveraging the opportunities of integrating AM and network operations could, in many cases, prove to be a cost-effective way of improving these indices.

Table 1: Customer Loss by Voltage Level [6]

	% of Incidents	% of Customer Interruptions	% of Customer Minutes Lost
Transmission faults	0.00	0.29	0.02
132 kV system faults	0.03	3.50	7.00
EHV system faults	1.14	7.22	2.55
MV system faults	12.74	68.29	48.04
LV system faults	64.77	13.67	25.98
Pre-arranged outages	21.32	7.04	16.42

In the next section, the CNAIM is briefly described and in Section 3, the methodology used in this paper is introduced. A case study, in which the above concept is applied, is presented in Section 4, along with the corresponding results. Finally, the conclusions are drawn and future work is described in Section 5.

DNO COMMON NETWORK ASSET INDICES METHODOLOGY [3]

The CNAIM is "a common framework of definitions, principles and calculation methodologies, adopted across all GB DNOs, for the assessment, forecasting and regulatory reporting of asset risk". This methodology defines the process for evaluating condition-based risk for DN assets and has been produced by a team of dedicated engineers from all the UK DNOs.

In the CNAIM, several condition parameters, such as age, observed and measured condition information, can be combined in an appropriate way and yield a single value, which indicates the overall condition of an asset. This figure is called asset HI and can be of great importance in AM and network operation decisions. The present paper uses the term "Health Index" instead of "Health Score" as CNAIM does. Based on the HI of the asset, the corresponding probability of failure (PoF) can be calculated, as shown in (1). PoF is the first key parameter of this methodology. The second is Consequences of Failure (CoF), which is broken down into four categories, namely financial, safety, environmental and network performance. PoF and CoF are combined in order to derive a single figure for asset risk, expressed in monetary terms. The aforementioned process, which describes how the condition-based risk of an asset is calculated, is illustrated in Fig. 2.

$$\mathrm{PoF} = \mathrm{K} \times \left[1 + (\mathrm{C} \times \mathrm{H}) + \frac{(\mathrm{C} \times \mathrm{H})^2}{2!} + \frac{(\mathrm{C} \times \mathrm{H})^3}{3!}\right] \quad (1)$$

where H is the HI of the asset and K, C are constants.

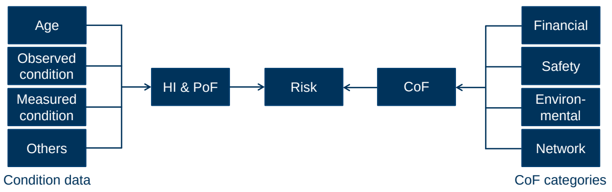

Figure 2: CNAIM Process Overview

METHODOLOGY

In an appropriate DN, which is presented in the next section, a number of network reconfigurations are evaluated in terms of losses and overall system risk. Reconfigurations are implemented using the simple branch exchange method, i.e. closing one switch and opening another one at the same time. The minimum cost of annual energy losses and overall system risk determines the optimal configuration of the network. System risk consists of transformer (TX), circuit breaker (CB) and overhead line (OHL) / underground cable risks. The risk calculation models for the above-mentioned asset types are detailed in the following subsections.

Overhead Line and Circuit Breaker Risk Calculation Model

The calculation of CoF for OHLs and CBs is based on CNAIM. As regards financial, safety and environmental CoF, the appropriate figures are selected from the above-mentioned methodology, while Network CoF is evaluated according to the CNAIM LV & MV Asset Consequences process. The equation that gives the Network CoF of these assets is shown in (2). At this point, it should be noted that 6.6 kV, 11 kV and 20 kV are classified as High Voltage (HV) in the CNAIM, however this paper refers to these voltages as MV, as this is the case in most other countries.

$$\begin{gathered}\text{OHL / CB Network CoF} = \\ [(\mathrm{UCML} \times 60 \times \mathrm{NC} \times \mathrm{ST} \times (1 - \mathrm{R1})) + \\ (\mathrm{UCML} \times 60 \times \mathrm{NC} \times \mathrm{RT} \times (1 - \mathrm{R2})) + \\ (\mathrm{UCI} \times \mathrm{NC} \times (1 - \mathrm{R1}))] \times \mathrm{F}\end{gathered} \quad (2)$$

where UCI and UCML are the unit costs to the DNO per customer interruption and customer minute lost, respectively. NC is the number of customers, ST is the switching time and RT is the restoration time (both in hours). R1 and R2 are the proportions of customers restored through immediate and after manual switching, respectively. Finally, F is the proportion of failures that result in interruption to supply.

The second factor, which is needed to calculate risk, is PoF. As far as CBs are concerned, PoF is based on HI, which is related to asset condition. The condition data that are used for the calculation of the HI are shown in Table 2. Regarding OHLs, PoF is considered equal to the failure rate of MV lines (0.035 f/yr·km), which has been calculated using typical national fault statistical data [6], and is assumed constant regardless the condition of the line.

Table 2: CB Condition Data

MV Switchgear (GM) - Primary		
HI	**4.00**	Initial HI × HI Factor
PoF	**0.00148**	According to (1)
Age	**37**	
Initial HI	**2.51**	Related to Age
HI Factor	**1.59**	Related to Condition
Observed Condition Factor	**1.43**	
External Condition	1	Normal Wear
Oil Leaks / Gas Pressure	1	Slight Leak
Thermographic Assessment	1	Above Ambient
Internal Condition & Operation	1.2	Some Deterioration
Indoor Environment	1.3	Deteriorated Environment
Measured Condition Factor	**1.23**	
Partial Discharge	1.1	Medium
Ductor Test	1.1	< 10% Deterioration
IR Test	1.1	< 10% Deterioration
Oil Tests	1.1	< 10% Deterioration
Temperature Readings	1	Above Ambient
Trip Test	1	Pass

It is worth mentioning that, in the case of an OHL/CB (active) failure, the nearest CBs operate in order to clear the fault. Consequently, part of the healthy network is removed from service and more specifically the section that was supplied through the CBs. Following the operation of the breakers, the fault should be detected and isolated before the CBs can be reclosed. After the detection, isolation and switching (the total time interval required for these actions is called switching time), the power supply, between the switches around the failed component and the activated CBs, is restored. The rest of the customers are restored after the repair process has been completed, unless they can be supplied through an alternative route, e.g. by closing a normally open point [7]. The procedure explained above, in terms of Network CoF, is illustrated in Fig. 3.

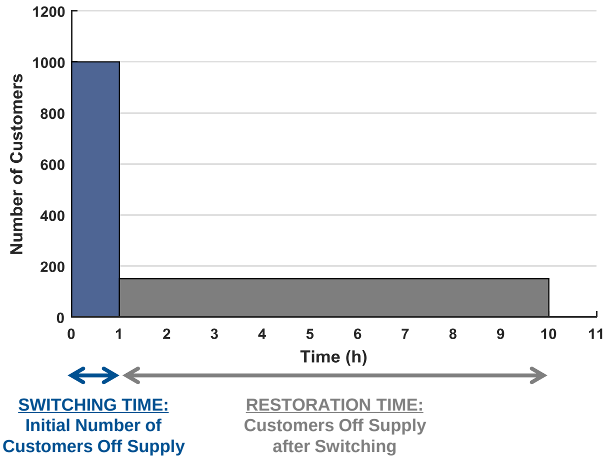

Figure 3: Network CoF – LV & MV Assets [3]

Transformer Risk Calculation Model

The process begins with collecting the appropriate condition data for the TX and then calculating the associated HI and PoF, according to CNAIM, as shown in Table 3. Regarding TX CoF, there are four dimensions, as mentioned in the previous section. Financial, safety and environmental consequences are specified using CNAIM. As far as Network CoF are concerned, this paper is based on [8], where Network Risk can be broken down into the expected annual cost of CIs and CMLs, as shown in (3) – (5). These equations can be used to assess the Network Risk, when two transformers (or, more generally, two circuits) are connected in parallel, which is the case in the network of the case study that will be examined in the next section.

$$CI = (PoF_1 + PoF_2) \times DF \times NC \times UCI \tag{3}$$

$$CML = (PoF_1 + PoF_2) \times DF \times NC \times (R2 \times ST + (1 - R2) \times RT) \times UCML \tag{4}$$

$$\text{TX Network Risk} = CI + CML \tag{5}$$

where RT is the average time to restore at least one of the parallel branches (ST and RT, here, in minutes) and DF is the proportion of faults that result in a customer interruption, generally because two outages occur at the same time. This can happen for a number of reasons – common mode failure, second circuit tripping because of increased loading or second circuit failing while the first is being maintained / repaired. It should be noted that PoFs in these equations include the PoFs of the CBs associated with the TXs, i.e.:

$$PoF_i = PoF_{TXi} + PoF_{CBi} \tag{6}$$

Table 3: TX Condition Data (Main TX Component)

EHV Transformer		
Overall Transformer HI	**5.66**	max(Main TX HI,Tapchanger HI)
Probability of Failure	**0.0294**	According to (1)
Main Transformer Component		
HI	**5.66**	Initial HI × HI Factor
Age	**50**	
Initial HI	**3.69**	Related to Age
HI Factor	**1.53**	Related to Condition
Observed Condition Factor	**1.40**	
Main Tank Condition	1	Normal Wear
Coolers / Radiator Condition	1.2	Some Deterioration
Bushings Condition	1.2	Some Deterioration
Kiosk Condition	1.1	Some Deterioration
Cable Boxes Condition	1	Normal Wear
Measured Condition Factor	**1.10**	
Partial Discharge	1.1	Medium
Temperature Readings	1	Normal
Oil Test Factor	**1.1**	
Oil Condition Score	570	
Moisture Score	2	15 - 25 ppm
Acidity Score	2	0.10 - 0.15 mg KOH/g
Breakdown Strength Score	2	40 - 50 kV
DGA Test Factor	**1**	
% Change	0	Neutral
DGA Score	180	Previous DGA Score = 180
Hydrogen	0	0.01 - 20 ppm
Methane	2	10 - 20 ppm
Ethylene	2	10 - 20 ppm
Ethane	2	10 - 20 ppm
Acetylene	0	0.01 - 1 ppm
FFA Test Factor	**1**	
S (FFA value in ppm)	3	

CASE STUDY

Description

The methodology explained in the previous section is applied to a representative MV network of four feeders, supplied by two primary substations, where each feeder is based on the standard IEEE 33-bus network. Default values are considered for all input parameters, except for the line impedances (resistances and reactances), which have been reduced by 90%. Assuming an 11 kV, 9.9 MVA conductor with R = 0.1037 Ω/km, it can be derived that the total length of the standard IEEE 33-bus feeder is 198.5 km. However, using the modified impedances, it can be deduced that the respective length equals to 19.85 km, which is a typical length for an urban distribution feeder. Each feeder (F1 – F4) is considered to supply 3715 customers. There are also six more feeders, not shown, connected to each common busbar at primary substations X and Y. It is assumed that each one of them supplies 3000 customers. The network described above, is illustrated in Fig. 4 and the NC connected to each bus is detailed in Table 4.

Table 4: NC Connected to each Bus

Bus	NC	Bus	NC	Bus	NC
1	0	12	60	23	90
2	100	13	60	24	420
3	90	14	120	25	420
4	120	15	60	26	60
5	60	16	60	27	60
6	60	17	60	28	60
7	200	18	90	29	120
8	200	19	90	30	200
9	60	20	90	31	150
10	60	21	90	32	210
11	45	22	90	33	60

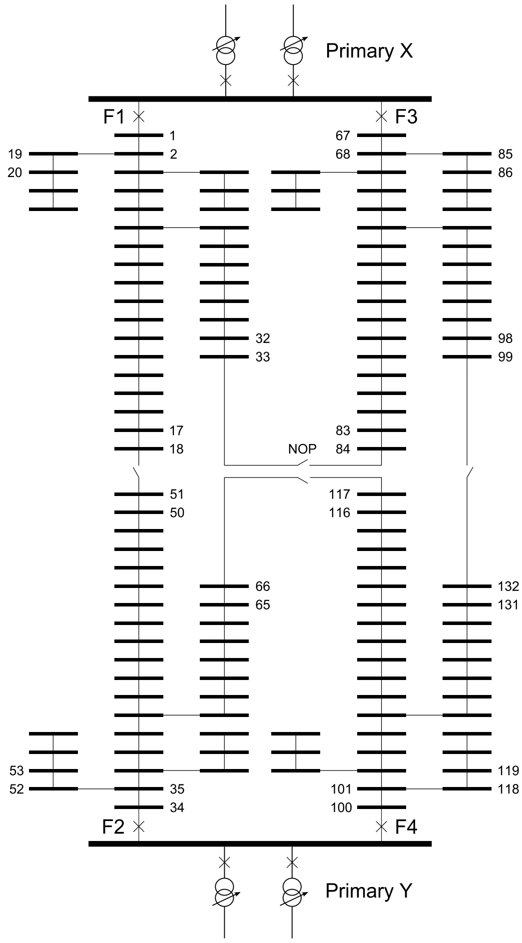

Figure 4: Case Study Network

As mentioned in the Methodology Section, several network reconfigurations are performed via operating a pair of switches at the same time, and for each possible configuration, a number of variables are calculated. These variables include losses and their corresponding value per year, asset risks and minimum voltage magnitude. Of all risk categories, only network risk is taken into account in order to decide the optimal network configuration, since transferring loads has an effect only on this specific risk category. Also, voltage is set at 1.06 pu before TXs.
The cost of annual energy losses (C_{Ly}) is given by:

$$C_{Ly} = \text{Losses} \times 8760 \times \text{LLF} \times \text{Energy Price} \qquad (7)$$

where LLF is the Loss Load Factor, which is equal to $0.5F + 0.5F^2$, when Demand Factor = 1. F is the Load Factor, which is assumed to be 0.5 and the energy price is considered to be 50 £/MWh (wholesale price).
Table 5 shows the HIs that have been considered for the TXs and the CBs in the Case Study Network. As can be seen in this table, the condition of the assets at primary substation X is assumed much worse than that of Y. It should be mentioned that in the present work, HIs are capped at a value of 15, instead of 10, as in the CNAIM. All other parameter values that have been used in this case study are shown in Table 6.

Table 5: Asset HIs

Primary Substation X		Primary Substation Y		Feeder CBs	
Asset	*HI*	*Asset*	*HI*	*Asset*	*HI*
TX 1	14.33	TX 1	5.66	F1 CB	4.00
TX 2	14.40	TX 2	6.52	F2 CB	4.00
CB 1	9.00	CB 1	4.00	F3 CB	4.00
CB 2	9.00	CB 2	4.00	F4 CB	4.00

Table 6: Case Study Parameter Values

Parameter	Value	Parameter	Value	Parameter	Value
K_{TX}	0.0454%	ST	1 h	F_{OHL}	75%
K_{CB}	0.0052%	RT_{OHL}	5 h	F_{CB}	55%
$C_{TX/CB}$	1.087	RT_{CB}	4 h	$R2_{TXs}$	50%
UCI	£5	R1	0%	RT_{TXs}	480 min
UCML	10 £/h	$R2_{OHL/CB}$	100%	DF	20%

Results

The results of the present case study are shown in Table 7. In this table five criteria are shown, according to which the network can be reconfigured. It can be seen that different criteria result in different network configurations. To begin with, minimum losses lead to the initial network configuration (illustrated in Fig. 4). OHL Risk becomes greater as the feeders get more asymmetrical, i.e. as load is transferred from one feeder to another. This is because, when a feeder becomes longer, the more likely it is for a failure to occur and when it does, more customers will be interrupted. In order to minimize TX Risk, load is transferred from primary substation X to Y, because of the bad condition of the former. The optimal network reconfiguration is achieved when both cost of annual energy losses and total network risk are considered.
The first two criteria do not take asset condition into account, while the latter three do. Comparing min Losses and min (C_{Ly} + Total Risk) criteria, it can be derived that there is a difference of almost £5,500 in terms of cost of annual energy losses and total network risk. Therefore, it can be seen that the integration of asset condition in the decision-making process of network operation can lead to an improved outcome in terms of the two aforementioned parameters.
It should be noted that not all possible combinations of open switches have been examined, because as the feeders become more asymmetrical, the more total OHL Risk and losses increase. Consequently, only five switches on either side of each NOP (referring to the

initial network configuration) have been considered for this case study.

Table 7: Case Study Results

Configuration for:	min Losses	min OHL Risk	min TX Risk	min Total Risk	min (C_{Ly} + Total Risk)
Open Switches	18-51 33-84 66-117 99-132	16-17 82-83 63-64 129-130	13-14 28-29 61-62 94-95	16-17 30-31 115-116 94-95	16-17 82-83 115-116 96-97
Losses (kW)	83.75	87.83	127.59	97.15	86.35
V_{min} (pu)	1.039	1.035	1.022	1.029	1.036
Total OHL Risk	£116,203	£113,404	£121,567	£115,162	£114,044
Primary X TXs Risk	£184,183	£186,139	£175,999	£177,737	£180,055
Primary Y TXs Risk	£18,929	£18,728	£19,770	£19,591	£19,353
Total TX Risk	£203,112	£204,867	£195,769	£197,328	£199,408
Total CB Risk	£1,244	£1,244	£1,244	£1,244	£1,244
Total Risk	**£320,559**	**£319,515**	**£318,580**	**£313,734**	**£314,696**
C_{Ly}	**£13,756**	**£14,426**	**£20,957**	**£15,957**	**£14,183**
C_{Ly} + Total Risk	**£334,315**	**£333,940**	**£339,537**	**£329,691**	**£328,879**

CONCLUSIONS & FUTURE WORK

This paper indicates that asset condition information can have a positive impact on network operation. More specifically, the methodologies described in Sections 2 and 3 have been applied to a representative MV DN and the results have shown that, incorporating asset condition (through HIs, PoFs and Risks) into network operations can result in reduced total network risk and cost of annual energy losses.

Particularly, the comparison between min Losses and min (C_{Ly} + Total Risk) criteria, has led to a difference of £5,500, which corresponds only to the four feeders of the Case Study Network, but a DNO, typically, has thousands of feeders like those. Therefore, the overall savings, for a DNO, can have a really significant value. Moreover, by transferring load from primary substation X to Y, it is expected that the ageing rate of the former will be reduced and accordingly is more likely to last longer.

The authors consider that an integrated power system AM and operations approach is critical for affordable, reliable and sustainable networks. In addition, this integration could be even more important in specific developing countries, where their networks operate with very high losses, frequent outages, very high temperatures and poor asset coordination.

Future work will use a more sophisticated optimization method, such as Particle Swarm Optimization or Genetic Algorithm, instead of the simple branch exchange method for the DN reconfiguration problem.

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