OPTIMAL INVESTMENT PLANNING THROUGH BALANCING LOAD GROWTH WITH NETWORK RISK

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ABSTRACT

Over the next 20 years in the UK, initiatives to help deliver government low carbon targets are likely to increase the take-up both of electric vehicles and of heat pumps. These additional loads will place greater demands on existing networks, leading to a greater level of network risk experienced by Distribution Network Operators.

Network reinforcement is the traditional way of mitigating such increased network risk. This represents a substantial investment, and because of the need to spend capital efficiently, such investments will need to be prioritized and targeted in those areas of highest risk or that deliver the greatest benefit.

This paper considers a case study based on a rural network in northern England, and forecasts how long the network will remain compliant with regulatory standards, and how that period of compliance can be extended by minor or major capital expenditure, in conjunction with active network management.
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INTRODUCTION

Projected Levels of Load Growth

During the period from 1920 to 1970, consumption of electricity in the UK increased at an average annual rate of over 9% per year [1, 2]. In particular, during the 1960s consumption doubled from around 100 TWh to 200 TWh per year. In contrast, the years from 1970 to 2010 have seen much lower annual growth rates, averaging around 1% per year throughout that period, to reach a present level of around 340 TWh.

It is possible that the growth in electricity consumption over the next 20 years will follow the established trend of the previous 40 years, averaging around 1% annually. One recent report produced for the UK regulator OFGEM outlines five possible scenarios for the period to 2050, ranging from a slight decrease in demand to the fastest growth rate still averaging less that 1% per year [3]. A successor report considers four scenarios, with growth rates up to 2025 averaging 1.4% in the fastest growth scenario [4].

These issues are addressed in detail by McKay, who summarises current per capita energy consumption patterns in the UK as including 18 kWh/day for all electrical uses, 40 kWh/day for heating, and 40 kWh/day for transport. This is the total energy demand which needs to be reduced substantially over the next 20 to 40 years [5]. The proposal to reduce the heating load is by the use of ground-sourced and air-sourced heat pumps, combined with greater efficiency of house insulation. The combined effect would be to replace 40 kWh/day of heating fuel (mostly gas) with 12 kWh/day of electricity, releasing at least double that amount of heat from the ground or the air [5]. The proposal to reduce the total transport load is by extensive use of electric vehicles. This would replace 40 kWh/day of transport fuel (mostly oil-based) with 18 kWh/day of electricity [5].

Although net energy consumption is significantly reduced in this scenario, the electricity consumption is substantially increased, from 18 to 48 kWh/day, an increase of 167%. If this increase happened over the next 40 years, as McKay assumes, the annual growth rate would be around 2.5%. In this paper, McKay's baseline figure of 2.5% is assumed. Although higher than the assumptions in the OFGEM reports [3, 4], it is still less than one third of the growth rate actually achieved during the period from 1920 to 1970. Also, even if the underlying average growth rate were around 1.5%, it would be unevenly distributed, and could well reach 2.5% in rural areas such as that assumed in the case study in this paper.

Network Risk

As electricity consumption increases during the period 2010-2030, the distribution networks also become more heavily loaded, particularly at peak times. The UK standard for maximum levels of network risk is P2/6, endorsed by the regulator OFGEM [6]. It specifies for different load sizes the maximum permissible customer disconnection time in the event of a first outage (n-1), and for large enough loads, in the event also of a second outage (n-2).

For loads between 12 MW and 60 MW, the n-1 requirement is to restore supplies to all customers within 3 hours. Since there is no guarantee that a fault can be repaired within that time, the network design must provide 100% redundancy, most typically in the form of a duplicate, parallel circuit. If there is no duplication at the supply voltage (33 kV), then there must be the facility to reconfigure at a lower voltage (11 kV) to restore supplies to all customers.

As the load increases to a level above the rating of a single transformer (or the overhead line or underground cable supplying it), then at times of peak load it would not be possible to supply all customers, and some might need to be disconnected for the duration of a network outage, which could be longer than 3 hours, particularly if the effective demand peak lasts longer than 3 hours. If some customers can be transferred to alternative sources via the 11 kV network, then there is an increased potential for load growth. But the year will eventually come when, in an n-1 scenario, all customers who can be transferred have been, and the remaining load is still above the plant rating for a period in excess of 3 hours. In that year, the network no longer complies with P2/6. The year immediately before that is designated the Last Compliant Year (LCY).

As well as complying with P2/6, the Network Operator is obliged to report failure to supply customers, and is rewarded or penalized by the regulator based on the frequency, duration and extent of such interruptions. The cost of this, as well as the cost to the Network Operator of unscheduled repairs and asset deterioration as a result of faults, have been combined in a single measure of Network Risk, measured as an expected cost in £k per year. This measure has been published [7,8], and will be used in the economic analysis in the present paper.

Capital Investment Planning

Sometime before the LCY, it will therefore be necessary to undertake substantial capital investment, such as installing an additional transformer or uprating the existing transformers, to ensure that this part of the network remains compliant with the regulator's requirements concerning security of supply. There are a number of incentives, however, to avoid or at least to defer such capital investment if at all possible, including explicit financial incentives under the regulatory framework, the requirement to invest efficiently, shortage of available capital, shortage of skilled engineers, difficulties in obtaining planning permission, other competing projects, and uncertainty about future network and customer requirements.

It therefore becomes important to study projections for increased load in some detail, in conjunction with load flow models of the region of network under consideration, both with the network intact and under first circuit (n-1) and at higher load levels under second circuit (n-2) outage conditions. This is in order to determine for how many years the load requirements of groups of customers supplied from particular substations will have their power needs met at the minimum level of security required by OFGEM. The time to the LCY is the main indicator of how long capital expenditure in that region can reasonably be deferred.

UK CASE STUDY NETWORK

The network used to illustrate these concepts is in a rural area in the North of England. It includes 6 primary substations, supplying around 28000 customers, fed from a single supply point substation at 33 kV, as shown in Figure 1. The network covers a large geographic area in a residential location, which is likely to contain an above-average proportion of early adopters for new technology such as heat pumps and electric vehicles. Some parts of the area do not have mains gas, and this is also likely to result in an above average penetration of heat pumps during the period 2010-2030. Many of the customers travel around 30-40 km to work, which is within electric vehicle range. All these considerations make it reasonable to assume an annual load growth of 2.5%.

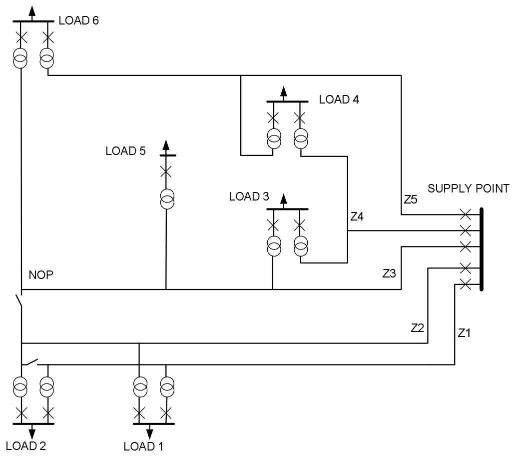

Figure 1 – Case study network

The network is subdivided into five distinct protection zones, designated Z1 through to Z5, which will be used in the analysis. All but Z4 each contain over 20 km of overhead line running through exposed, hilly locations, giving the network an above average likelihood of failure.

Case Study Risk Analysis

Table 1 shows the peak winter load at each of the six load points, and the nameplate rating of each transformer at that location. It also shows what proportion of the load can be transferred at 11 kV to another substation outside the group shown in Figure 1 (column A), or via another protection zone to another substation within the group (column B), or cannot be transferred at all without unacceptable volt drop (column C).

It can be seen from Table 1 that Load 1 is already greater than the capacity of a single transformer at that location. In the event of the loss of Z1, there would be insufficient capacity to meet peak demand. Transferring 7% of this load outside the group would help, but would not be sufficient. Further load would need to be transferred within the group to bring the load below the 12.5 MVA nameplate rating of the single remaining transformer

Load Point	***Peak MVA***	***Transf. MVA***	***A***	***B***	***C***
1	14.2	12.5	7%	68%	25%
2	10.8	12.5	0	55%	45%
3	6.7	12.5	64%	22%	14%
4	15.6	30	17%	75%	8%
5	6.7	23	0	100%	0
6	7.1	12	35%	11%	54%

Table 1 – Characteristics of 6 loads

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However, transferring it to load point 2 would be of limited use, as the loss of Z1 also removes a transformer from that load point 2, and the remaining transformer is operating at 86% of capacity. Most of the available transfer from load point 1 is to load point 2, but there is also some to load point 5, and using this would avoid overloading the remaining transformer at load point 2.

So the n-1 contingency of losing a single protection zone is manageable in 2010, at present loads. But if loads increase throughout this network at an annual rate of 2.5%, the scope for transfer becomes more limited each year. Detailed load flow analysis indicates that the overhead line rating of the remaining Z2 circuit is exceeded, and manual switching of 33 kV circuits, including the normally open point (NOP) shown in Figure 2, becomes necessary by 2012. Applying load flow analysis for each successive year shows that the LCY for failure of Z1 is 2014. Beyond this date, capital investment (or active load reduction) would be required to ensure compliance with P2/6.

Similar analysis can be carried out for the failure of each of the other circuits. The analysis of a failure of Z3, for example, shows that a severe limitation is imposed by the low rating of a part of the Z5 circuit (12.0 MVA at the supply point substation). This gives a LCY of 2014 for the loss of this circuit. Overall, the LCY across all five circuits is 2014, which can be achieved by the use of extensive Active Network Management

Minor Capital Investment

In order to extend the LCY beyond 2014, capital investment would be necessary. This could be substantial, for example building new circuits, new transformers at existing substations, or even building whole new substations and reallocating the load. The cost of such major work would be of the order of £10 million but, properly designed, the resulting infrastructure should be sufficient to cater for forecast demand growth up to the end of the period under consideration (2030) and beyond.

A less expensive alternative would be to undertake a number of smaller capital investments. One example would be to reconductor several km of line, mostly in Z5, to increase its rating. The cost of this would be of the order of £1.5 million. Its effect, in conjunction with extensive active network management, would be to extend the LCY for 3 years, to 2017. After 2017, a major system redesign costing around £10M would become necessary.

Economic Analysis

Table 2 gives a typical cash flow that might result from the decision to defer major capital expenditure by carrying out such relatively minor construction projects. Note that, as well as the capital costs themselves, the level of network risk has been calculated as described in [8]. This includes an increasing level of risk as loads increase (in 2015 and 2016), and an additional doubling of risk in years during which construction projects take place (2014 and 2017) when there are planned outages of long duration which leave the network more vulnerable. Once major network redesign has taken place, network risk reverts to a lower level, excluding the contribution which arises from the increased load levels.

£k	*Network Risk*	*Capital Cost*	*Total Cost*	*Discount at 7%*
2013	280		280	280
2014	580	1530	2110	1962
2015	300		300	259
2016	310		310	249
2017	640	10000	10640	7959
2018	184		184	128
TOTAL	12294	11530	13824	10837

Table 2 – Costs of minor projects in 2014, major redesign in 2017

Table 3 shows the equivalent cash flow, where minor projects are not carried out, but instead the major network redesign takes place 3 years earlier, in 2014. The cost of such redesign is the same in both years. Although the scope might be less in 2017 on account of the minor projects already carried out, it seems likely that construction costs would escalate at above inflation rate, and cancel out the benefit.

£k	*Network Risk*	*Capital Cost*	*Total Cost*	*Discounted at 7%*
2013	280		280	280
2014	580	10000	10580	9839
2015	184		184	159
2016	184		184	148
2017	184		184	138
2018	184		184	128
TOTAL	1596	10000	11596	10692

Table 3 – Costs of major redesign in 2014

Comparing the total costs for each option, it can be seen that implementing the minor projects adds £2.228 M to the total cost, of which 69% is capital expenditure, 14% is additional risk during construction, and 17% is additional risk due to increased utilization of unreplaced assets.

Against this, there is a benefit in deferring the cost of network redesign by 3 years. This is shown in the final column of Tables 2 and 3, where the cash flow is discounted at 7%, a rate commonly adopted by the Network Operator to evaluate projects. At this rate, the net present costs of the two options are within 1.5% of each other. This suggests that, at discount rates of 7% or below, the Network Operator's optimal policy is to undertake major redesign in 2014. At discount rates above 7%, however, it is better to undertake the minor projects in 2014 and defer major redesign by 3 years.

Two further benefits of deferring major redesign have not been costed, but are worth noting. First, the load growth may not continue to be as high as 2.5%, and in that case it may be that network redesign can be deferred for longer than 3 years, perhaps even indefinitely if demand growth levels off. Second, any major network redesign should be sufficient to cater for forecast demands for a minimum of 20 years, which requires accurate prediction of what the demands on the network are likely to be throughout that period. The longer such redesign can be delayed, the more accurate such predictions are likely to be, and the more robust the resulting network design.

Other non-costed factors which might affect the decision to defer major redesign, but which could affect it either way, include the level of active network management required in each case, the accuracy of the cost estimates of the various options, the expected relative availability of both capital and engineering resources in the years 2014 and 2017, and the expected real cost escalation of capital projects during that period.

CONCLUSIONS

During the period 2010-2030, load growth on the UK electricity distribution networks due to the increasing penetration of heat pumps and electric vehicles, particularly in rural areas, could be as high as 2.5% annually. This rate of growth could increase the level of risk on existing networks beyond what is acceptable to customers and the regulator, and require minor or major capital expenditure to alleviate that risk.

Detailed consideration of a case study based on an actual rural network in the north of England illustrates that the last year in which networks are compliant with the required standards (LCY) can be calculated. Beyond the LCY, network reinforcement will be required. The case study considers two reinforcement options: 1) minor reinforcement in 2014 followed by major reinforcement in 2017 or 2) major reinforcement in 2014. Analysis quantifies the economic benefits of implementing each option and concludes that it is more economic to implement option 2 although there are a number of other factors that need to be considered. The approach developed for, and illustrated by this case study could be applied at different voltages levels and different locations throughout the distribution network.

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