An Interdisciplinary Method to Demand Side Participation for Deferring Distribution Network Reinforcement

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Abstract— **This paper presents an interdisciplinary socio-technical methodology for quantifying the value of demand side participation (DSP) in deferring network reinforcement. The methodology forecasts how many years load growth a section of network can accommodate before components exceed their standard rating. The approach identifies components within the network which are thermally vulnerable and uses power flow sensitivity factors to assess the value of applying real power reductions, through demand side participation, at different substations to relieve thermally constrained components. The third stage of the methodology socially characterises the load points. This is achieved by using socio-demographic data to map out the number and type of customers connected to each load point. This information is used to gauge the potential social acceptance of demand side participation schemes for different types of consumer. The final stage combines the power flow sensitivity factors, calculated in stage 2, with the social findings, calculated in stage 3, to calculate the optimum socio-technical solution. The methodology is illustrated by a case study that uses an existing rural distribution network in northern England.**

Index Terms—**Demand Side Management, Demand Side Participation, Distribution Network, power flow sensitivity factors**

I. Introduction

Within the UK, and internationally, there is increasing pressure on distributors to become more efficient, to provide increased reliability with ageing assets and to facilitate the transition to a low-carbon economy. In order to meet these expectations distributors are looking to innovative techniques which may be suitable for deployment on their networks. Demand Side Management (DSM) is one such technique that has the potential to address a plethora of network issues [1].

Furthermore the demand side is an important element of the emerging smart grid paradigm with the potential to deliver flexible demand, increased network utilization and enhanced customer choice [2]. A number of recent reports have explored the role demand side management could play in future network scenarios [3,4] and efforts have been made to understand demand in greater detail [5,6] with particular emphasis placed on increased price responsiveness of electricity demand.

The UK regulator, Ofgem, has opened up discussion on the role of the consumer and the demand side in future distribution networks [7,8]. Some commentators have suggested that demand side management represents an opportunity to engage consumers as the co-managers of demand, rather than passive beneficiaries of supply [9]. Greater participation of the demand side has the potential to deliver significant and cost effective impacts in the areas of climate change, fuel poverty and distribution network design and control [7].

Traditionally, demand side practices within the UK electricity industry have been focused towards managed rather than participatory actions [10]. While it may be possible to determine and overcome the technical and commercial barriers to demand side activities, to achieve the full potential of demand side actions requires suppliers and network distributors to engage with electricity consumers.

Mutual engagement between industry actors and consumers in the UK would permit movement beyond DSM and towards Demand Side Participation (DSP) with its emphasis placed on electricity user's participation and requirements. This paper presents research that adopts an interdisciplinary approach using tools and techniques from power systems engineering and social anthropology to develop a socio-technical methodology for assessing the value of DSP in deferring distribution network reinforcement.

II. Methodology Overview

The purpose of this paper is to outline the development stages of the methodology and, in particular, to focus on the technical stages and underline the role of power flow sensitivity factors and thermal vulnerability factors in the framework. The main stages of the methodology are summarised below:

Stage 1: Last Firm Year. Apply a fault to each protection zone in turn and calculate the number of years until the network becomes overfirm and will require reinforcement. This is achieved by conducting offline power flow analysis with an annual load growth percentage and considers all possible network configurations to balance load across the

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load group until the latest last firm year (LFY) is identified. This baseline LFY is used to calculate the additional number of years load growth that can be accommodated with DSP. The first stage also identifies thermally vulnerable components in the network which constrain further load growth.

Stage 2: Power Flow Sensitivity Factors and Thermal Vulnerability Factors. Generate thermal vulnerability factors (TVFs) to evaluate the value of applying load reductions, through DSP, at different substations to relieve thermally vulnerable components. This is achieved through the use of power flow sensitivity factors (PFSFs) and the thermal rating of network assets.

Stage 3: Social Index. Socially characterise load points according to social factors. This is accomplished by disaggregating load points into different demand customers using geo-demographic data. Each type of demographic user is given a numerical value which indicates their potential willingness to engage with DSP schemes. This allows each substation to be rated according to how socially acceptable demand side actions are to the type of customers connected to it.

Stage 4: Socio-technical Solution Calculate the socio-technical optimum solution by multiplying the social index figure, determined in stage 3, by the TVF, assessed in stage 2, to give the optimum socio-technical solution.

III. Methodology Stages

A. *Stage 1: Last firm Year*

The unutilized capacity or headroom within an existing network is used to calculate the number of years before investment is required to reinforce. Within the UK the primary standard which triggers network reinforcement is Engineering Recommendation P2/6 [11]. For different load sizes ER P2/6 stipulates the maximum permissible customer disconnection time in the event of a first outage, also known as network minus one or n-1, and for large loads a second outage, or n-2. The first stage in the methodology calculates the period of time a section of network, under n-1 conditions, can accommodate year on year load growth until reinforcement is need to meet the requirements of ER P2/6.

Last firm year gives an indication of how long capital investment can be deferred in a network. For a given load growth, the length of time before reinforcement is required is the time taken for the loading of the network to reach the maximum rating of the most vulnerable component. When this limit is reached it may be possible to extend the period of load growth by re-configuring the network to reduce the power flow through the constraining component by transferring some of the load to an alternative circuit with spare capacity. However there will be a year when all possible load transfer options have been exhausted and the network loading exceeds the maximum rating of the most vulnerable component. The year immediately previous to that year has been labeled the Last Firm Year (LFY). The first stage of the methodology identifies the optimum network configuration with the best LFY along with the thermally vulnerable component which constrains the network.

The notion of years to reinforcement has previously been used by Blake et al [12] to determine optimal network investment planning and by Li [13] to develop long run marginal cost pricing models. The work presented in this paper applies LFY as a unit of measurement to assess the value of using DSP to defer network reinforcement in comparison with traditional network solutions.

B. *Stage 2: Power flow sensitivity factors and thermal vulnerability factors*

The second stage in the methodology calculates the value of reducing demand at each load point to relieve thermally constrained components which limit the number of years load

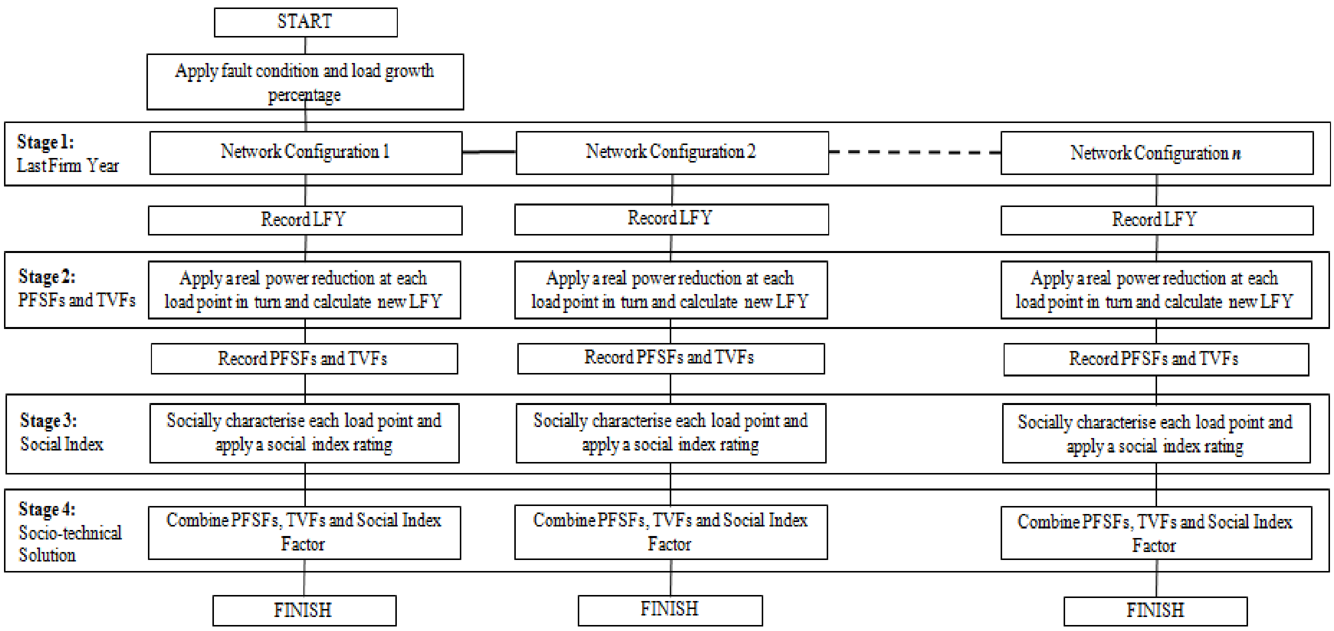

Fig. 1. Methodology Overview

growth. Power flow sensitivity factors (PFSF) are central to the proposed methodology and describe the impact of a change in real power at a network load node to the change in power flow through a network component [14]. At distribution level PFSF have been used to develop control strategies for generation output based on distribution thermal limits [15] and voltage constraints [16].

In particular the work presented in this paper draws on and extends the research by Jupe and Taylor [17] which linked PFSF with thermally vulnerable network components. However, instead of using PFSFs to developed distributed generation control strategies, the research presented in this paper applies part of the methodology in [17] to assess the value of applying real power reductions at different load points, using DSP, to relieve thermally constrained components and defer network reinforcement.

PFSF are used to identify the contribution of each load point to the thermally constrained component. A full AC load flow solution can be used to calculate PFSFs using the inverse Jacobian matrix. Given a perturbation in real power the changes in bus voltages and angles can be calculated, as in (1).

$$\begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} = [J]^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial\theta}{\partial P} & \frac{\partial\theta}{\partial Q} \\ \frac{\partial V}{\partial P} & \frac{\partial V}{\partial Q} \end{bmatrix} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad (1)$$

Where V is the vector nodal voltages, θ is the vector of voltage angles and J^{-1} is the inverse Jacobian matrix. Therefore, the PFSFs due to a demand reduction in real power at node m is given by (2)-(5).

$$f(V): \frac{dP_{i,k}}{dL_{P,m}} = \left(\frac{\partial P}{\partial |V|/|V|}\right)_{i,k} \left(\frac{d|V_k|/|V_k|}{dL_{P,m}} - \frac{d|V_i|/|V_i|}{dL_{P,m}}\right) \quad (2)$$

$$f(\theta): \frac{dP_{i,k}}{dL_{P,m}} = \left(\frac{\partial P}{\partial \theta}\right)_{i,k} \left(\frac{d\theta_k}{dL_{P,m}} - \frac{d\theta_i}{dL_{P,m}}\right) \quad (3)$$

$$f(V): \frac{dQ_{i,k}}{dL_{P,m}} = \left(\frac{\partial Q}{\partial |V|/|V|}\right)_{i,k} \left(\frac{d|V|/|V|_k}{dL_{P,m}} - \frac{d|V|/|V|_i}{dL_{P,m}}\right) \quad (4)$$

$$f(\theta): \frac{dQ_{i,k}}{dL_{P,m}} = \left(\frac{\partial Q}{\partial \theta}\right)_{i,k} \left(\frac{d\theta_k}{dL_{P,m}} - \frac{d\theta_i}{dL_{P,m}}\right) \quad (5)$$

Where $f(V)$ and $f(\theta)$ are functions of voltage magnitude and voltage angles, $(\delta P / \delta|V|/|V|)_{i,k}$, $(\delta P / \delta\theta)_{i,k}$, $(\delta Q / \delta|V|/|V|)_{i,k}$ and $(\delta Q / \delta\theta)_{i,k}$ represent elements within the Jacobian and $d|V|/|V|_k/dL_m$, $d|V|/|V|_i/dL_{P,m}$, $d\theta_k/dL_{P,m}$ and $d\theta_i/dL_{P,m}$ represent elements within the vector $[\Delta\theta \quad \Delta V]$. A load reduction of real power at node m due to DSP scheme is given by $dL_{P,m}$.

This gives a combined overall power flow sensitivity factor ($SSF_{i,k,m}$) from node i to node k, due to a load reduction of real power at node m, given below in (6)

$$SSF_{i,k,m} = \left[\left(\frac{\partial P}{\partial\theta}\right)_{i,k}\left(\frac{d\theta_k}{dL_{P,m}} - \frac{d\theta_i}{dL_{P,m}}\right) + \left(\frac{\partial P}{\partial V}\right)_{i,k}\left(\frac{dV_k}{dL_{P,m}} - \frac{dV_i}{dL_{P,m}}\right)\right] + j\left[\left(\frac{\partial Q}{\partial\theta}\right)_{i,k}\left(\frac{d\theta_k}{dL_{P,m}} - \frac{d\theta_i}{dL_{P,m}}\right) + \left(\frac{\partial Q}{\partial V}\right)_{i,k}\left(\frac{dV_k}{dL_{P,m}} - \frac{dV_i}{dL_{P,m}}\right)\right] \quad (6)$$

PFSFs describe the change in power flow through a component due to a change in power at a particular load node. Individual network components can be identified by their position in the network and the nodes they are connected to. A high PFSF indicates that a reduction in nodal power leads to a large change in power flow through a component. However a small power flow change in a component with a low thermal rating may be more critical than a large PFSF in a component with a large rating. Jupe and Taylor [17] developed the notion of Thermal vulnerability factors (TVF) as a way of linking PFSF with the thermal sensitivity of network components, and is described in (7)

$$TVF_{i,k,m} = \left(\frac{SSF_{i,k,m}}{S_{i,k(\lim)}}\right) \quad on\ S_{base} \quad (7)$$

Where $TVF_{i,k,m}$ represents the thermal vulnerability factor of a component, from node i to node k, due to a real power reduction at node m. $SSF_{i,k,m}$ represents the power flow sensitivity factor of component, from node i to node k because of a real power reduction at node m, $S_{i,k(\lim)}$ represents the thermal limit of a component, from node i to node k, and S_{base} is a predefined MVA base [17]. TVFs allow component thermal vulnerabilities, relative to each other, to be assessed across the network and different nodal power changes to be analysed. This stage in the methodology calculates which load point is technically the best to reduce demand from to relieve thermally vulnerable components.

C. Stage 3: Social Index Factors

The thirds stage in the methodology reflects the consumer participation aspect of demand side activities by capturing the social acceptability of DSP for different demographic groups. The methodology seeks to understand and gauge the different responses energy consumers are likely to have to demand side actions and identify which customers are mostly likely to be willing to participate in demand shifting activities. This can be achieved by using geo-demographic data to categorize consumers according to a range of factors, such as (but not limited to) age, employment, education and house stock.

Geo-demographics is widely defined as the analysis of people by where they live [18]. The term has come to describe the classification of small geographic areas and draws general conclusions about the characteristics and behaviors of the people who live there. The underlying principle is that similar people live in similar places, have similar lifestyles and do similar things. The methodology applies this principle by using geo-demographic data to classify different types of electricity consumer and gauge their potential response to engaging with demand side participation schemes.

The third stage of the methodology uses the output area classification (OAC) demographic data set [19] to map out the types of customers connected to each substation. The OAC is based on publically available UK census and council ward data and uses cluster analysis to break the population down into 7 fundamental demographic types, based on a number of attributes such as education, income and house type. Social science research is currently being conducted to map out and quantify how each one of these seven core groups responds to demand shifting. When this key piece of research has been completed, each of the seven OAC categories will be assigned a numerical value indicating the socially acceptability of demand shifting. This process will allow different substations to be numerically ranked according to how acceptable demand side participation is to the customers to whom a particular substation is connected. The numerical figure indicates acceptability at each load point is labeled the substation's social index factor.

D. Stage 4: Socio-technical Solution

The final stage of the methodology multiplies the technical aspects of demand shifting, calculated in stage 2, along with the social factors, considered in stage 3, to give a numerical solution. This answer is socio-technical in nature, as in balances the technical requirements of the network distributor and social needs of consumers.

The network benefit of applying demand side actions are captured in the thermal vulnerability factors which indicate the impact of applying demand reductions at different substations while the social index factors represent the social implications of applying demand side actions to consumers.

The final step in the methodology recognizes the need to acknowledge both sides of the demand coin, the network and the consumers, in designing and implementing demand side participation schemes. The fourth stage calculates the socio-technical optimum by multiplying the TVFs by the social index factors to identify the substation which balances the technical requirement to relieve network constraints as well as locating consumers who most likely to consider providing the required demand reduction. Solutions can be assessed either in terms of the technical aspects of DSP or the social characterisation of substations or combination of the two, a socio-technical solution, can be used to identify and assess the impact on deferring network reinforcement.

IV. Development Stages Illustrated by an Existing Rural Distribution Network

The methodology is illustrated by a case study on an existing rural distribution network in northern England. The case study considers the first two stages of the methodology by identifying thermally vulnerable components, calculating the LFY and assessing the value of applying a demand reduction at different substations to relieve the thermally vulnerable component and extend the LFY.

A. Network Description

The network selected to illustrate the methodology has a meshed topology with predominantly overhead line infrastructure at 33kV. The case study network consists of 6 primary substations fed by a single 33kV supply point, as shown in Figure 2. The overhead lines were split into five protection zones, labeled Z1 through to Z5, with the substations indicated as load points. Static ratings along with the maximum loading levels reported by CE Electric UK Long-Term Development Statement [20] were used to model the network along with current operational practices.

The network covers a large rural region supplying mainly residential customers. Analysing socio-demographic data about the customers in the region, gathered from council ward statistics, suggested that the load group contained a higher than average proportion of early adopters of new technology such as electric vehicles and heat pumps, especially as many customers do not have access to mains gas. Given these considerations an annual load growth of 2.5% was applied.

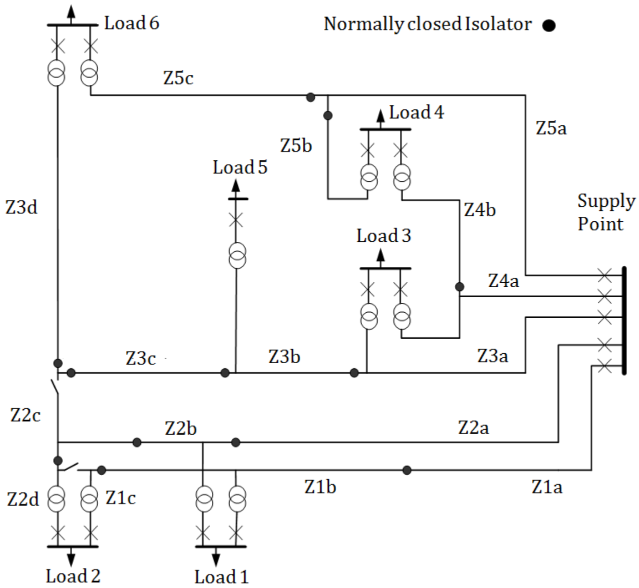

Fig. 2. 33 kV Case Study Network

B. Assessment of the Last Firm Year and identification of thermally vulnerable components

Initially the last firm year was calculated for different network topologies and the constraining component identified. This was achieved by applying a fault to the first protection zone, Z1, and running a full ac load flow for the base case operating conditions and checking whether a thermal or voltage constraint was exceeded. If no constraint was met, the network loading was increased at each substation by the annual load growth percentage and the procedure repeated until a constraint was breached. When a constraint was met, the year before was labeled as the LFY and the constraining component recorded. If available, reconfiguration options were used to transfer load away from the constraining circuits to neighboring circuits with spare capacity to extend the LFY. When all these options had been exhausted the greatest LFY and the constraining component was recorded.

The 2010 peak loads are shown in Table 1, along with the nameplate ratings of the transformers for each load point. The first column, A, indicates the percentage of load that can be transferred at 11kV to another substation outside the group. The second column, B, shows the amount of load that can be transferred to another substation within the group while the third column, C, is the proportion of load which cannot be transferred away from the substation without breaching additional network constraints, such as unacceptable voltage drop or exceeding circuit breaker protection limits.

Load Point	Peak Load MVA	Transf. Rating 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. Load Point Characteristics

It can be seen from Table 1 that load point 1 already exceeds the single transformer rating at that location and would require some of the load to be transferred away from the substation following an n-1 fault. Transferring 7% of the load outside the group would still leave 13.26MVA and would therefore require further load to be transferred internally within the load group to bring the load level below the 12.5MVA name plate rating of a single transformer. This illustrates that n-1 contingency for losing a single protection zone may require load to be transferred to relieve thermally vulnerable components. As the load level increases year on year, the scope for transfer becomes more limited as more components approach their ratings. Detailed power flow analysis is required to identify the thermal vulnerable components and calculate the last firm year.

The worst case scenario for protection zone Z1 is when a fault is applied in zone Z1-A which would place stress on circuit Z2. The normally open point next to Z2-C can be closed to allow circuits Z2 and Z3 to operate as a ring. Load can be transferred from load point 1 to load point 5 which relieves circuit Z2 and allows the network to remain firm until 2014 when Z3-A becomes the constraining component at 101.1% overfirm.

Protection zone 2 is similar to the first zone except circuit Z1 not Z2 is now initially required to supply the full load to load point 1 and 2. The two affected transformers at load point 1 and 2 cannot be fed by closing the normally open point at Z2-C and opening the appropriate isolator on Z2 as this would exceed the circuit break protection settings. Therefore load must be transferred away from load point 1 and 2 to other load points. Transferring load outside the group and to load point 5 allows the network to remain firm until 2014 when circuit Z3-A becomes the constraining component.

Circuit Z3 is arguably the key circuit in the network and the options following a network fault are limited. Circuit Z3 supplies load point 3, 5 and 6 and therefore solutions should seek to transfer load away from these substations. The worst case, a fault in Z3-A, can be rectified for a couple of years by, opening the isolator at the end of Z3-A, closing the normally open point at Z2-C and transferring load out of the group away from load point 3 outside the group.

A fault in Z4-A places stress on circuit Z5 which has to carry the full load of load point 4. Transferring load away from load point 5 to load point 3 and outside the group allows the network to remain firm until 2017 when Z5-A becomes the constraining component at 12.323 MVA or 103% overfirm.

Following a fault in Z5-A the full load of substation 5 must be supplied by circuit Z4 when Z4-A becomes the critical component. Transferring load away from both load points 3 and 4 relives the circuit Z4-A and allows the last firm year to be extended to 2014.

Table 2 shows the last firm year after a fault has been applied to each protection zone along with the thermally vulnerable components which constrain the network. It can be seen from the table that protection zone Z3 is most vulnerable to load growth as it gives the lowest LFY. Identifying the constraining component is non-trivial as shown by fault zone 1 and 2 where Z3-A is the limiting component and protection zone 3 and 5 where Z4-A limits the number of years load growth. The table can be used to identify which sections of network would provide the most benefit from reinforcement, in this case circuit Z3 and in particular overhead line Z3-A.

Fault Zone	LFY	Thermally Vulnerable Component	Rating, MVA	Power Flow, MVA	Rating, %
Z1	2014	Z3-A	26.3	26.582	101.10%
Z2	2014	Z3-A	26.3	26.468	100.60%
Z3	2013	Z4-A	16.7	16.784	102.30%
Z4	2016	Z5-A	12.0	12.323	102.69%
Z5	2014	Z4-A	16.7	17.513	104.80%

Table 2. Last Firm Year following n-1 fault conditions

Each load transfer option results in a slightly different network configuration which in turns gives a different last firm year. Table 2 shows the optimum LFY for the case study network under n-1 conditions using only active network reconfiguration. Stage 1 of the methodology identifies the location of thermally vulnerable components which limit the amount of load the network can accommodate. Stage 2 of the methodology uses power flow sensitivity factors to assess the value of reducing demand at each load point to relieve the constraining components.

C. *Power flow sensitivity factors and thermal vulnerability factors*

PFSFs indicate the extent to which power flow changes within components due to a change in network conditions, such as real power reductions due to demand side actions. However a large change in power flow, indicated by high sensitivity, does not necessarily mean a component is thermally vulnerable unless its rating is taken into account. A flow chart of the procedure used to generation PFSFs and TVFs for different network topologies and loading conditions is given in figure 3. Initially a fault was applied to the first protection zone and the network reconfigured to give the optimum LFY, calculate in stage 1, and the appropriate loading conditions applied.

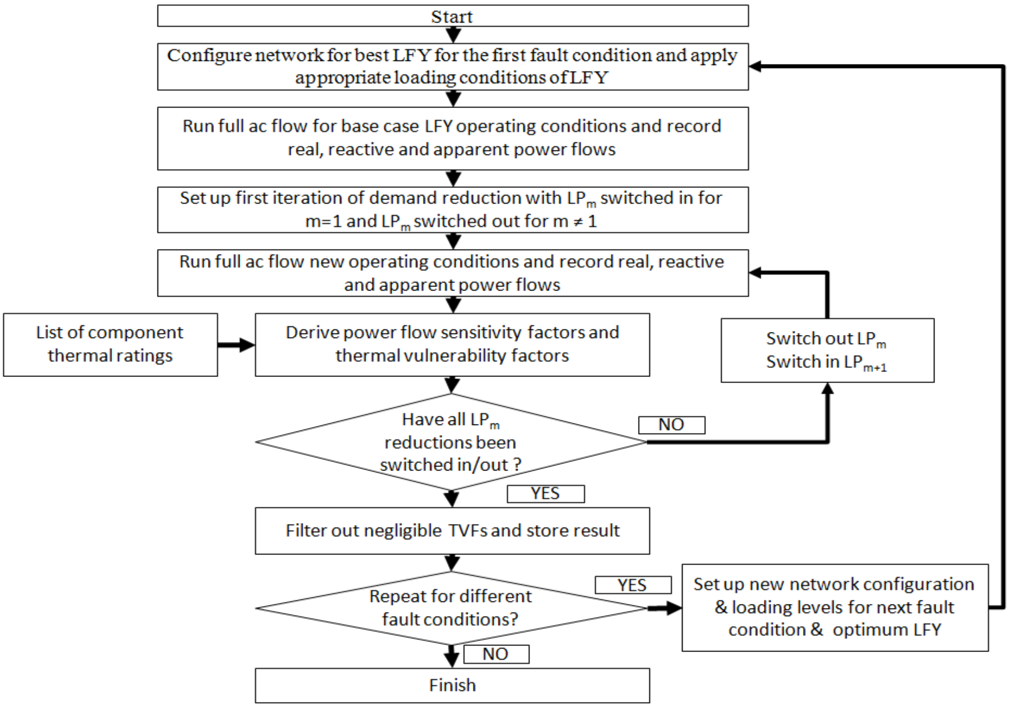

Fig. 3. Flow chart for the assessment of power flow sensitivity factors and thermal vulnerability factors

A full ac flow load was conducted to establish 'base case' operating conditions and the real, reactive and apparent power flows recorded.

The procedure was continued by applying a real power reduction of 0.1 pu (in this case on 100MVA base) at each substation, labeled as load point on the flowchart, and recording the resulting power flows. The demand reduction was switched in and out for each substation in the network. The procedure generated power flows for each component, for each demand reduction, which were stored in matrix form. PFSFs were established by using the base case real and reactive power flows, the new power flows due to demand reduction at each load point and the thermal ratings of each component.

Voltage limits were not directly formulated as constraints in the methodology, although the Jacobian matrix could be used to calculate the bus sensitivities to power reductions, instead they were monitored during the assessment using functionality in the simulation software.

This stage of the methodology generates a TVF for each network component for each network configuration. Table 2, calculated in stage 1, can be used to filter out negligible TVFs and focus on the critical network components by considering the components which limit network load growth. Figure 4 graphically represents the thermal vulnerability factors for critical network components resulting from single demand reduction at each load point.

D. Thermally vulnerable components resulting from single demand reduction at each load point for each protection zone

The assessment of TVFs applied to the case study network has been used to examine the relationship between a single demand reduction and the ability to provide relief to thermally constrained components following a network fault. For example following a network fault in protection zone 1 and reconfiguring the network to achieve the optimum LFY results in component Z3-A becoming the limiting asset. Figure 4 shows the range of TVFs that are generated following a 0.1 pu demand reduction at each load point for this network configuration. Inspecting the results it can be seen that a single demand reduction at load point 5 gives the greatest thermal relief, reducing the loading through the constrained component by 25% which is equivalent to a TVF of 0.25. Topologically, load point 5 is primarily fed from the supply point via circuit Z3-A and therefore a change in power flow due to a demand reduction is most notable in the primary supply circuit. In comparison a reduction at another load point, such as load point 3, would see the benefits of reducing loading split over the two supplying circuits Z4-A and Z3-A.

Following a network fault in protection zone 1, the LFY is achieved by closing the normally open point at Z2-C and balancing load across the network. This new meshed network configuration is evident in figure 4 as it can be seen that applying demand reductions at load points 1 and 2, which are non local to the constrained component Z3-A, provide a thermal rating reduction of 18% and 19% respectively.

TVFs relate the change in demand at different substations to component thermal vulnerabilities across the network. TVFs can be interpreted in two ways. The first is that all load points that result in a high TVF can provide support to relieve thermally vulnerable components. Inversely the constrained component is vulnerable to increased load at substations which have high TVFs. For protection zone 1 the TVFs are spread reasonably evenly over all the substations which indicates that the network is uniformly loaded with respect to component Z3-A.

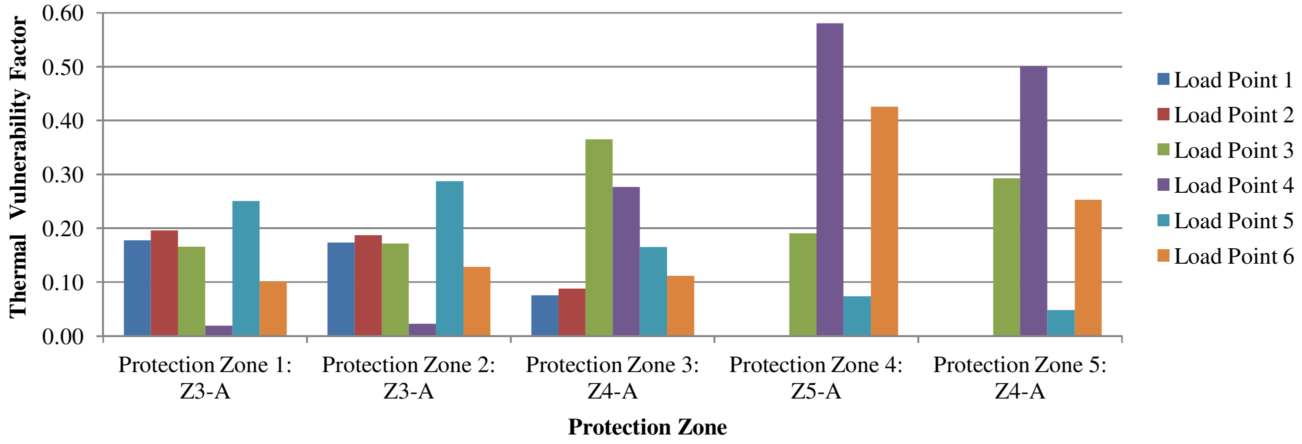

Fig. 4. Thermal vulnerability factors for the five constraining components which limit the optimum LFY after a single demand reduction at each load point

Following a fault in protection zone 2 the LFY of the network can be extended by reconfiguring the network in a similar manner to protection zone 1; closing the normally open point at Z2-C and balancing load across the group. Likewise component Z3-A becomes the constraining asset and a reduction at load point 5 provides the best thermal relief. Furthermore the high TVFs for load points 1, 2, 3 and 6 indicate that in this network configuration Z3-A is vulnerable to load growth at those substations or inversely demand reduction can provide support at those sites.

In order to extend the LFY following a fault in protection zone 3, the normally open point at Z2-C can be closed and load transferred out of the group away from load point 3. Annual load growth is constrained by component Z4-A. It can seen in figure 4 that applying a demand reduction at load point 3 provides the greatest benefit, followed by load point 4. Circuit Z4-A supplies load point 3 and 4 and therefore reducing demand at those substations will relieve the constrained component. Applying demand reductions at other load points, such as load point 5 and 6, relieves the loading along other circuits that supply the key load points 3 and 4 and will require less of the load to be carried by Z4-A.

The last two protection zones do not require the normally open point at Z2-C to be closed and therefore circuits Z1 and Z2 are not connected to the wider network and demand reductions at those substations provide no benefit to relieving thermally constrained components following a fault in protection zone 4 or 5.

Following a network fault in protection zone 4 the optimum LFY can be achieved by transferring the load away from load point 3 and 4 to outside the load group and results in Z5-A becoming the constraining component. Inspecting figure 4 it can be seen that demand reductions at the two substations, load point 4 and 6, which are fed via Z5-A give the greatest thermal relief. A demand reduction of 0.1 pu at load point 4 and 6 reduces loading through Z5-A by 58% and 43% of the components thermal ratings respectively.

A fault in protection zone 5 places additional stress on circuit Z4-A to supply load point 4. The latest LFY is found by transferring load away from load point 3 and 4, this is further reflected when applying demand reductions as load point 3 and 4 provide the greatest benefit in relieving Z4-A.

Table 3 shows the TVFs graphically represented in figure 4. By taking a total of all the TVFs it can be seen that applying load reduction at load point 4 provides the most benefit over all the protection zones, followed by load point 3. Therefore if a demand side participation was to be implemented to provide benefit for the whole network it would most beneficial to contract customers and load connected to substation 3 or 4.

Fault Zone	Thermally Vulnerable Component	Location of Demand Reduction					
		Load Point 1	Load Point 2	Load Point 3	Load Point 4	Load Point 5	Load Point 6
1	Z3-A	0.18	0.20	0.17	0.02	0.25	0.10
2	Z3-A	0.17	0.19	0.17	0.02	0.29	0.13
3	Z4-A	0.08	0.09	0.37	0.28	0.17	0.11
4	Z5-A	0.00	0.00	0.19	0.58	0.07	0.43
5	Z4-A	0.00	0.00	0.29	0.50	0.05	0.25
	Total	0.43	0.47	1.19	1.40	0.83	1.02

Table 3. Thermally Vulnerable Factors for critical network components resulting from single demand reductions at each load point

V. CONCLUSIONS

This paper presents a novel approach to selecting and implementing demand side actions which takes not only the technical aspects into consideration but also the social attributes of demand shifting. This approach allows a socio-technical approach to be adopted and the requirements of the network operator and the electricity user to be taken into consideration.

The units of last firm year can be used to quantity the benefit of using demand side actions to defer network reinforcement and compare them against alternative network solutions. Furthermore the use of power flow sensitivity factors along with thermal vulnerable factors can be used to identify which substation are technically the best to apply demand reductions at.

The methodology has been demonstrated on a case study network in rural northern England. Using the methodology it can be seen that applying demand reductions is not intuitive but impacts the network in a variety of ways and allows different facts to emerge. For example stage 1 of the methodology identifies that circuits Z4-A and Z3-A are the critical circuits in the network and would provide the most benefit from being reinforced. Likewise stage 2 of the methodology identifies that load point 3 and 4 would be the optimum substations to focus demand side participation schemes at.

Ongoing social anthropology fieldwork is underway to capture information on electricity customer's practices, which is required to develop the third stage of the methodology, the social index factor. Work is continuing on the methodology to develop control strategies to realize the potential of applying multiple demand reductions within a network.

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