VOLTAGE CONTROL OF DISTRIBUTION NETWORK USING AN ARTIFICIAL INTELLIGENCE PLANNING METHOD

Jianing CAO
University of Strathclyde – UK
jianing.cao@strath.ac.uk

Keith BELL
University of Strathclyde – UK
keith.bell@eee.strath.ac.uk

Amanda COLES
University of Strathclyde – UK
amanda.coles@cis.strath.ac.uk

Andrew COLES
University of Strathclyde – UK
andrew.coles@cis.strath.ac.uk

ABSTRACT

The paper explores the potential to apply an artificial intelligence planning approach to a distribution network so as to manage voltage with much less dependency on human intervention which is usually required to set control targets for controllers. This is achieved by the integration between a load flow simulator and a planner. To validate the methodology, simulations of a network model were carried out for regular control target setting and the results were compared against the setting of tap positions generated by the planner which takes in information from the load flow simulation results. By comparison, it was found out that the planner can improve the settings with fewer changes in transformer tap positions whilst keeping the voltage within the requisite limits.

INTRODUCTION

Voltage control issues have long been of great concern to engineers working on both transmission and distribution networks. It can be a challenging task to effectively coordinate different control mechanisms at various voltage levels. Furthermore, the increasing penetration of generation on the distribution network has also contributed to the complexity of setting voltage target and the coordination of actions of different devices [1].

There are many ways to control voltages in an electricity network, which can be briefly summarised as below:

- reactive power compensation by SVCs and mechanically switched capacitors (MSC)
- on-load tap changing transformers (OLTC)
- generator terminal voltage control
- line reactance compensators e.g. series capacitors [2]

Tolerant limits for voltages should be maintained at loading points according to Distribution Network Operators' (DNOs) licence obligations. That is, within ±6% of nominal for the voltages on the 33kV and 11kV networks and +10% and -6% for the 132kV network [3]. Transformer tap-changers are most commonly involved with voltage control schemes on the present distribution network in Britain. As part of automatic network voltage control schemes, tap changers usually respond to regulate in accordance with given set points. Engineering judgment is required in the determination of the target voltage setting. While this would ideally take into account both the fluctuations in demand and the operation of embedded generation at different points in the network, the rate at which voltage targets can be adjusted is limited by the practicalities of the control room engineer's wider responsibilities and the available network analysis tools. Under certain circumstances, this risks voltages going outside of limits. Moreover, there might be more tap movements than necessary to mitigate the changes in voltages with the consequence of increased wear on the tap-changer mechanism and the acceleration of aging of the equipment. This paper describes an alternative approach that can reduce both the burden on operational staff and wear on equipment while satisfying voltage limits.

AN ARTIFICAL INTELLIGENCE PLANNER

AI planning technology has a philosophy of domain independence: it makes use of a general search framework to solve a wide range of problems of different types. In this work, use is made of the general planner METRIC-FF [4]. METRIC-FF uses a generic heuristic to represent an intelligent decision process and minimise the time taken to compute solutions for complex problems. The key feature relative to conventional power system optimisations (excepting unit commitment) is that it plans actions over a given time period, i.e. it takes account of interactions between all modelled time steps/ a planning model has been created based on a discrete, linear approximation to the problem at hand and METRIC-FF used to find solutions, minimising a given objective function by successively adding constraints to previous solutions until a plan is found that satisfies all of them. The objective function includes different 'costs' to allow representation of multi-objective problems.

VOLTAGE CONTROL METHODOLOGY

The general planner described in the preceding section promises to allow setting of voltage controllers to be determined in such a way as to take account of, for example, forecast variations in demand and generation, and consequently voltage, through the course of a day and to minimise the number of control actions between time intervals and across a given period [5]. As well as the asset management benefit of minimising wear associated with electro-mechanical control actions, it also promises to minimise the number of voltage step changes associated with discrete control actions to control voltage. A set of linear sensitivity factors [2] is first defined that can be used by the planner in determining the effect of both control actions and independent, uncontrolled changes on the set of controlled voltages. However, because the relationship between power injections, flows and voltages on a real power system is non-linear, an extra loop is included to verify the plan found by the planner (Fig 1).

The contribution of this paper over the previous work [5] is its integration with load-flow software as discussed in the next section. External factors that can cause changes in voltage can also be considered and include demand or generation changes and faults on network branches. Control of voltage is achieved by changing the settings of the controllers, which includes tapping transformers up or down and, where available, switching MSCs on or off. Different 'costs' are used within the multiple-objective optimisation to resolve potential conflicts between the goals of respecting voltage limits, ensuring coordination between different devices and minimising the number of control actions. The objective function is shown as below.

$$PM = \alpha * T + \beta * M + \gamma * LV + \delta * HV \qquad (1)$$

- PM: Planner metric
- T: Transformer turns
- M: MSC switches
- LV: low voltage
- HV: high voltage

The 'costs' of control actions α and β to change tap position and open or close an MSC switch respectively can be set in accordance with advice from asset managers on the impact on equipment condition. In this study, the following values have been used: $\alpha = 0.1$ and $\beta = 0.1$. In addition, γ is the relative, likelihood-weighted 'cost' of an unplanned disturbance causing a voltage on the controlled network to rise above the upper limit and δ is that of an unplanned disturbance causing it to fall below the lower limit. While these are inevitably subject to some degree of judgement, consideration can be made of fault statistics and errors in forecast demand or outputs of generation. In the example study reported here, the following values have been used: γ=infinity and δ=0, and the lower bound of voltage is set to be -5% and the upper +5%. In this work, the core of the planning tool was applied to a distribution network which was modelled with distributed generation, demand and voltage controllers such as tap-changing transformers. The core planning models, specified the PDDL 2.1 (Problem Domain Definition Language) [6] are automatically generated from the IPSA output, using a script.

Integration with a load flow simulator

In the prototype application described here, the load flow simulator used is IPSA+ [7]. This provides a facility by which Python [8] can be used to set simulation initial conditions for modelled scenarios, run a simulation and extract results. A Python script has therefore been developed to manage the outer loop depicted in Fig 1 and provide the integration of the load flow validation with the core planner. As well as managing each step of the process, the script can identify whether a plan succeeds in keeping voltages within limits for all time intervals within the modelled period and provides updated sensitivity factors for any excessive voltage excursions, particular to the conditions for that particular time.

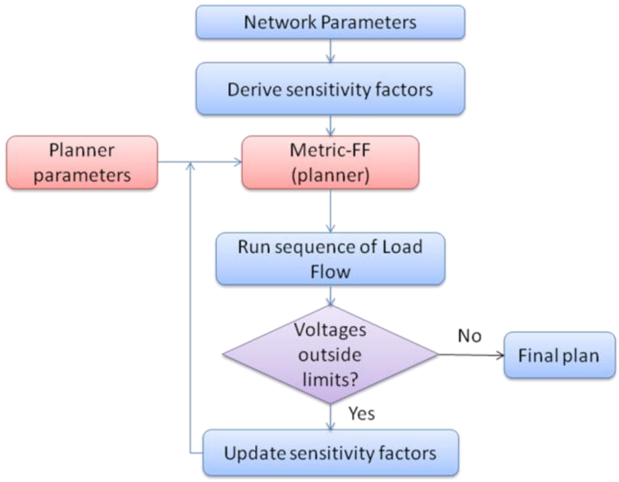

Fig. 1: Load flow simulator and the planner

EXAMPLE APPLICATION

Network model

To test and demonstrate the method described above, a test model of an 11kV distribution network has been used, shown in Fig. 2. The model and its data were developed as part of the AuRA-NMS project [9]. Grid power at 33kV is fed into the distribution network through two 10MVA 33/11kV OLTCs with tapping range of 20% in 16 steps of 1.25% (±10% from nominal) [10]. Loads are connected to various points and voltages at buses C1 and C2 were recorded due to their high likelihood of wide voltage excursions. A distributed generator (DG) is connected at bus E1. The model was simulated for a day of operation using 30 minute time intervals starting from midnight. The voltage limits to be respected in the results were taken to be ±5% of nominal.

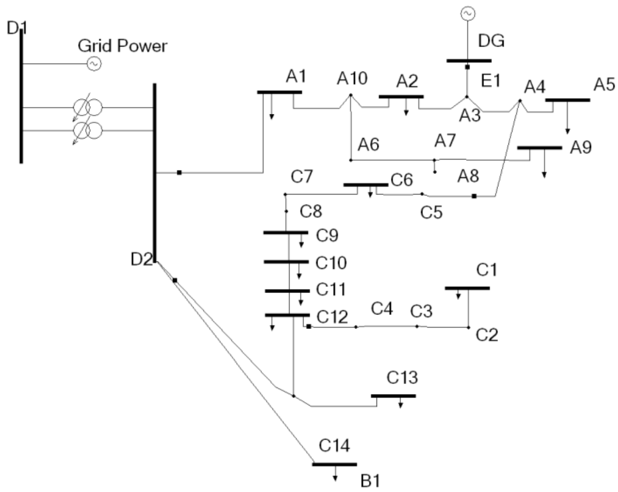

Fig. 2: 11kV Distribution Network Model

Load profile

Demand at each load point on the network was assumed to vary in accordance with national demand as reported by the transmission system operator in Britain [11], and is shown in Fig 3.

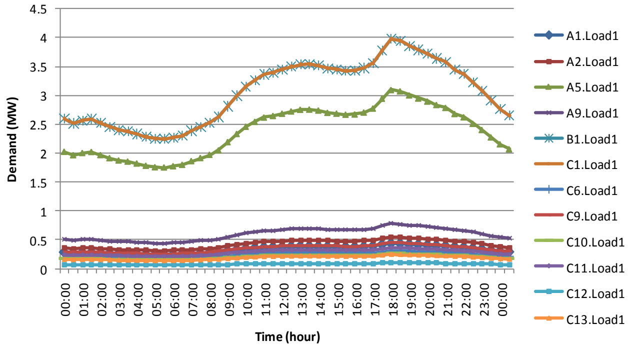

Fig. 3: Load profile for the distribution network

Generation profile

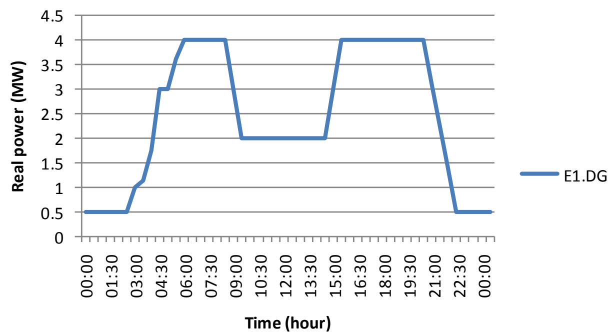

Fig. 4: Distributed generator power output

The DG in the model was assumed to be a Combined Heat and Power Plant with capacity of 4 MW. To comply with its generation activities throughout a day, in the test scenario it was assumed that the generator provided maximum power when space and water heating are most likely to be needed [12]. The generator's reactive power capability was assumed to be between 0 and 1.95 MVAr. Fig. 4 illustrates the generation profile for the DG throughout a day.

SIMULATION RESULTS

The results reported here are for a peak demand day (as shown in Fig. 3). Performance of the planner was tested under 3 different conditions: the generator set to be in voltage control mode, unity power factor mode and power factor control mode. Furthermore, two base case control settings were developed with which to compare the time series of settings determined by the planner: one in which the tap positions of the transfers were set to be constant; the other in which regulation of the voltage at the LV side of the transformers, i.e. bus D2, was enabled by means of automatic on-load tap changes to achieve a voltage target set at a constant value throughout the day of 1.0 per unit.

The entire simulation process is summarised as below.

1. Set the voltage target of the transformers to be 1.0 per unit and run load flows for each time interval to get a sequence of tap positions and voltages as base case 1;
2. Set the tap position of the transformers to be nominal and, by means of a set of load flows, obtain the resultant voltage profile as base case 2;
3. Feed the planner with sensitivity factors and initial conditions derived from load flow results and generate a new sequence of transformer tap settings;
4. In a sequence of load flows, set the tap positions according to the planner's control output and compare against the base case.

Fig. 5 depicts the tap position of the transformers under different scenarios and Fig. 6 the profile of the minimum voltage across the network.

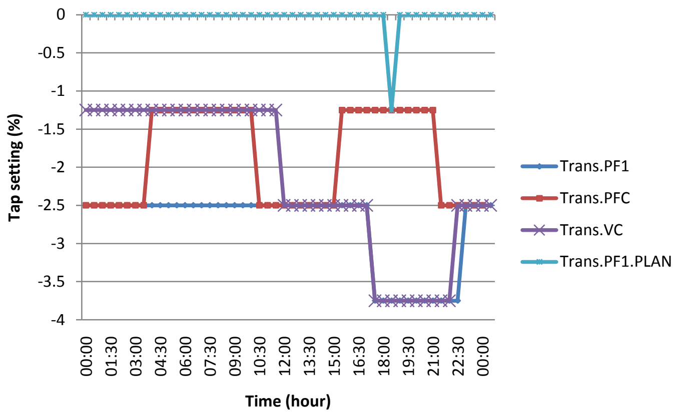

Fig. 5: Tap settings of transformers

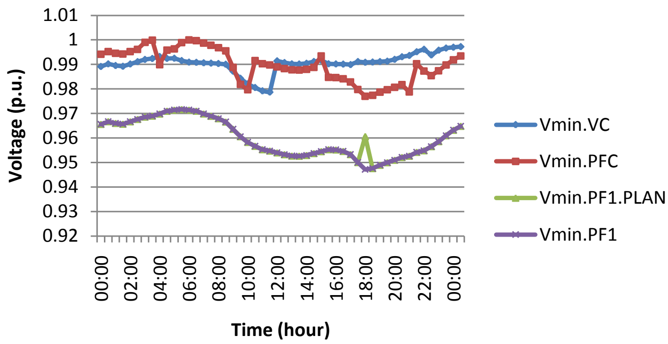

Fig. 6: Minimum voltage in the network

Voltage control (VC) mode

Under this mode, the DG scheduled its reactive power to maintain the voltage at bus E1, where it is connected, as close as possible to the nominal value. As a result, the upper reactive power limit of the generator was reached at many time slots in which the output was set to be 1.95 MVAr. In base case 1, the tap settings of the transformers (Trans.VC in Fig.5) were changed three times between -1.25% and -3.75% when a constant target voltage was set at the LV side of the transformers. However, in base case

2 in which the tap position was set to be nominal, i.e. at the middle of the range, the minimum voltage profile (Vmin.VC in Fig.6) was well within ±5% as shown in Fig. 6 and the planner left the tap positions constant at nominal values.

Power factor control (PFC) mode

To ensure an acceptable level of reactive power export from the DG to the grid, the power factor of the DG was controlled to be 0.8 [13] by regulating the MVAr being generated. The tap settings of the transformers (Trans.PFC in Fig.5) were changed three times in the period between -1.25% and -2.5% when the target voltage of 1.0 per unit was to be achieved. With the tap positions set to be nominal, the minimum voltage (Vmin.PFC. in Fig.6) was around 0.975 per unit. The planner left the tap settings at the nominal position.

Unity power factor (PF1) mode

The DG is providing only real power under this mode since the power factor was assumed to be 1. Therefore there was no reactive power support from the DG to support the voltage across the network. Consequently, the voltages were more likely to reach their required limits compared to the case under voltage control mode. The tap position (Trans.PF1 in Fig.5) varied from -3% to -2% when the voltage target at D2 was set to be 1.0 per unit (base case 1). Under nominal tap settings (base case 2), the minimum voltage (Vmin.PF1 in Fig.6) at 18:00 hours was 0.947 per unit, which was less than the 0.95 per unit limit. With changed settings generated by the planner (Trans.PF1.PLAN in Fig.5), the overall voltage was improved to a higher level and the minimum voltage (Vmin.PF1.PLAN in Fig.6) became around 0.96 per unit.

FUTURE WORK

The role of the planner will be further explored in a larger distribution network with more DGs, loads and transformers as well as other voltage controllers such as MSCs in order to test and verify its benefits in respect of more complex coordinated control problems. The voltage planner's robustness to forecast errors will also be tested along with further work on alternative strategies for the modification of initial voltage control plans in which differences between (non-linear) load flow solutions and a (linear) plan are significant.

CONCLUSIONS

A voltage planning methodology within a distribution network has been introduced with the aim of finding a sequence of control settings that allow voltage limits across a network to be respected while minimising the number of individual control actions. Performance of the prototype system on a network including a number of substations has been demonstrated. It is concluded that integration of a planner based on artificial intelligence with a load flow simulator succeeds in meeting the objectives under different generation control modes. In the test studies conducted to do date, the approach succeeds in resolving interactions between generation, demand and transformer tap changes on a distribution network. When the generator was operating under the unity power factor mode, the voltage profile is improved with fewer changes in tap positions and there will be less the wear-and-tear and asset management cost on the equipment.

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