CONTROL OF ACTIVE NETWORKS

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SUMMARY

High penetration of distributed generation is currently limited by passive operating methods of distribution networks.

At distribution level, insufficient measurements are available to allow satisfactory control, so measurement is extended through the use of state estimation. Aspects that are described in this paper include optimal measurement location, the problems occurring with few measurements, and load models used for “pseudo-measurements”.

Two control philosophies are described. The first, applicable to smaller network segments, is a local control, working with existing control devices such as transformer automatic voltage control (AVC) relays. The second philosophy is optimal control with constraints.

INTRODUCTION

High penetration of distributed generation is currently limited by the passive operating methods of distribution networks.

Automatic Voltage Control (AVC) with current compounding applied to distribution transformers usually assumes a simple R+jX or Z∠θ network model which, combined with radial power flow, allows the AVC system to maintain the voltage of the network within limits. When distribution networks become active, this network and load model no longer applies. With the export of power from the generating station, a voltage difference is often created. The resultant voltage rise along the feeder from the substation to the distributed generation can cause the feeder voltage to exceed its upper limit.

STATE ESTIMATION

Before suitable control techniques can be applied to the network, an improved knowledge of the network condition, or state, is required. Usually, at distribution level, insufficient measurements are taken to allow satisfactory control, so measurement is extended through the use of state estimation techniques.

Principles of State Estimation

State estimation has been widely used on transmission networks to assess the network operating conditions given a set of redundant measurements. Since redundant measurements are not available on distribution networks, distribution state estimation algorithms have to use a large number of load pseudo-measurements, discussed below. The state estimation algorithm is normally developed as a weighted least squares minimisation problem as shown in equation (1) [1]. Here, \( x \) is the system state vector (usually busbar voltage magnitudes and angles), \( z_m \) is an available measurement, \( \tilde{z}_m = h_m(x) \) is the corresponding measurement estimate and \( \eta_m \) is the measurement error. Each error is weighted using its standard deviation \( \sigma_m \).

\[
\begin{align*}
\min \ J(x) &= \sum_{m=1}^{M} \left( \frac{\eta_m}{\sigma_m} \right)^2 \\
&= \sum_{m=1}^{M} \left( \frac{z_m - h_m(x)}{\sigma_m} \right)^2
\end{align*}
\]

Equation (2) is evaluated with the most recent values of the state variables until a convergence condition is met. \( H \) is the measurement Jacobian matrix and \( W \) is a diagonal weighting matrix whose elements are the inverse of the measurement variances.

\[
\begin{align*}
x_{k+1} &= x_k - G_k H_k^T \left( H_k W H_k^T \right)^{-1} (z_k - h_k(x_k)) \\
G_k &= \left[ H_k^T \left( H_k W H_k^T \right)^{-1} \right] \left( z_k - h_k(x_k) \right)
\end{align*}
\]

A distribution state estimator based on equation (2) was included in a distribution management system controller (DMSC) with the aim of estimating network voltage magnitude at each point on the network. This estimation algorithm was extended to a statistical distribution state estimator (SDSE) by obtaining the variances of the estimated voltage magnitudes. The diagonal elements of the matrix \( G \) provide the variances of the estimated quantities.

The output results of the SDSE can be used to control the distribution network actively. The estimated uncertainties of the voltage magnitudes depend largely on the error of the voltage measurements. They are less affected by the error in the load pseudo-measurements.

Sources of Error with Distribution State Estimation

When transferring the techniques of state estimation to distribution networks there are additional aspects that must be considered. They focus on the causes of ill-conditioning of the gain matrix \( G \), which can lead to poor convergence, or non-convergence, of the iterative state estimator.
**Pseudo-measurements.** The distribution state estimator is expected to have a large number of load pseudo-measurements. [2] suggests that this may cause problems of instability due to increased poor conditioning of the gain matrix. They proposed LDU matrix decomposition to overcome this.

**Network Impedances.** Adjacent long and short lines (i.e. large and small impedances) are also a source of ill-conditioning [3]. The authors proposed an orthogonal decomposition method. This feature of state estimation can be expected to have an effect where there are very low impedance lines coupling busses.

**Virtual Measurements.** The combination of measurements with very large and very small weighting factors leads to ill-conditioning of the gain matrix $G$ [4]. The use of equality constraints to fix known values, e.g. zero injection at a non-load bus, can improve numerical stability.

**Scaling.** Poor scaling of measurement values has been identified as another cause of ill-conditioning of the gain matrix [5]. It is usual for power system problems to be evaluated with a per unit base of 100 MVA. While this is satisfactory for transmission system state estimation, the above suggests that for distribution state estimation the base should be reduced.

All of these issues suggest the use of improved solution algorithms through matrix computation techniques in order to improve the performance of the state estimation.

A common theme running through all of the above issues is that the measurement Jacobian $H$ contains values of widely differing orders, causing numerical storage errors when manipulated. Therefore, all of the proposed techniques for improvement avoid squaring $H$ to prevent propagation of these errors.

The task for the implementer of state estimation is to select the technique, or combination of techniques, that will produce the best convergence of the state estimation for a given network.

**Measurement Location**

Applied to distribution networks, state estimation differs from that applied at the transmission level, in that its purpose is normally to extend observability. Given the size of the distribution networks, it is impractical to have measurements on each node of the networks. Therefore, measurement location for distribution state estimation is conceptually different to that of transmission networks. Distribution networks offer limited measurements; P and Q injection/flow measurements are expensive so estimator observability is achieved using a large number of load pseudo-measurements.

Normally, voltage measurements are preferable to flow measurements to assess voltage profile on the network. Therefore, key voltage measurements from locations that would have significant impact on the state estimates are considered, and used together with many load pseudo-measurements. The measurement location algorithm presented in [6] was used to locate such potential points on the network.

**Load Models**

For pseudo-measurements, loads are usually modelled as Gaussian distributions with their mean at half the transformer rating. The large number of these pseudo-measurements can cause the state estimation to converge incorrectly. In light loading conditions the actual flow measurements will be small while the load pseudo-measurement values are relatively large and these act in opposition causing the estimator to converge to an incorrect local optimum.

As a solution it is proposed to scale the loads in proportion to the actual flow measurements into each load group [7]. The actual measured values would not then be in opposition to the pseudo-measurements. A potential problem resulting from this is that a very small load on a feeder would result in some extremely large weights on the pseudo-measurements, which may result in further convergence problems. Additionally, it is necessary to correctly match actual load flow measurements in the network to load groups, including distributed generation.

As a further refinement it is proposed to take the measured load for the group and distribute it to each load in the group in proportion to its rating, scaled according to load type, time of day, day of week and season. In the UK profiles are available for different load types. In order to implement this it would be necessary to estimate the proportion of each load type connected at each point.

**SEGMENT CONTROL**

Segment control is aimed at a single control point, such as an AVC system at a primary substation supplying a radial or ring connected network, but with little linkage to other parts of the system. Its principal aim is to support existing AVC schemes with minimum additional equipment and infrastructure, and aims to be independent and self-contained. State estimation estimates the voltage of all nodes within the network. The target voltage applied to the AVC relay is then adjusted upwards or downwards to prevent excursions of any node voltages from the segment control limits.

The distributed generation will normally employ voltage regulation to ensure its point of connection does not exceed regulatory limits. Normally the upper control limit applied is beneath the regulatory limit, and if it is exceeded the generation is curtailed to maintain the voltage at this limit. The segment controller’s upper limit for this node should be slightly lower than the generator’s limit, so when the voltage approaches the upper limit the segment controller reduces the target voltage on the AVC relay, which maintains the voltage.
within the generator’s control limits without the need to curtail generation.

This basic principle has been implemented into the Automatic Voltage Reference Setting algorithm [8, 9]. The algorithm has been implemented on substation control hardware by Econnect Limited as part of a demonstration project at two sites in the UK. Both of these sites are part of the 11 kV distribution network. One has five radial feeders, two of which have distributed generation connected. The other site is part of a two-substation parallel-connected network with a total of seven radial feeders, a heavy industrial load at one substation and a windfarm.

Results from this project suggest that the AVRS algorithm will be suitable for controlling networks of this complexity, where there is a single control point (substation voltage).

AREA CONTROL

A more advanced form of control is area-based control. Area control of the network utilises a distribution management system controller (DMSC). The DMSC has three functions: network assessment via state estimation, optimisation of the network controls and execution of the controls.

In addition to the AVC relay, the network may have Var compensators that can participate to provide a combination of control actions to increase the generation. The optimiser provides the most favourable control options for any given operating condition by observing all the operating constraints on the network.

The area-based control of the distribution network was implemented using the DMSC. The control actions were based on an optimum power flow (OPF) algorithm. The OPF objective function was formulated to minimise the costs of the transformer tap operation $T_i$, the reactive power absorption $Q_k$ and the curtailed generation $P_GN$ as shown in equation (3) subject to network and control limits. The cost of each control variable is represented by $C_{ik}$, where $x$ is $G$, $Q$ or $T$ for generator curtailment, Var compensator and tap control respectively.

$$\text{Minimise } \phi = \sum_{i=1}^{N} C_{ik} \left( T_i + Q_k + P_GN \right)$$

subject to the limits:

OLTC tap:

$$T_{min} \leq T_i \leq T_{max}$$

Available reactive power:

$$Q_{min} \leq Q_k \leq Q_{max}$$

DG output power:

$$P_{cur} \leq P_{G} \leq P_{Gmax}$$

Network voltage:

$$V_{min} \leq V_i \leq V_{max}$$

Line power flow:

$$S \leq S_{max}$$

Usually, the cost of the transformer tap operation is very low. However, the number of tap operations can reduce the lifetime of the OLTC equipment.

The control solutions proposed by the OPF algorithm should not radically deviate the network from the current operating point once the control actions are executed. This has been done by optimising the control actions at the operating conditions estimated by the SDSE. The load injection at each node was re-calculated using the estimated voltage magnitudes and angles. The voltage boundaries for optimisation were further reduced by the uncertainty of the estimated voltage magnitudes. The calculated load injections from the estimator and the estimated voltage magnitudes were then used in the controller.

The DMSC has been applied to a section of a Generic Distribution System (GDS), shown in FIGURE 1. The windfarms at busbars 11 and 51 are sized to keep the network within limits without the use of active control. In order to create a situation in which the DMSC can have some effect, the windfarm at busbar 51 was artificially increased to 3 MW / 0.8876 MVAR while the windfarm at busbar 11 was kept at its nominal capacity (0.75 MW / 0.2219 MVAR). The primary substation tap was at 0.95 pu. The increased injection of active power at busbar 51 resulted in voltage violation around busbar 51.

In the controller algorithm, the costs of control actions were set as $C_G > C_Q > C_T$. The transformer tap upper limit was reduced to 0.96 pu in order to force multiple actions (otherwise 1.05 pu). The solution to this case provided by the controller is shown in FIGURE 2. The vertical axis shows the voltage magnitude and the horizontal axis shows the direct path busbar numbering from the primary substation to the windfarm at node 51, i.e. busbar path 1-96-19-28-34-65-88-51. The curve $NTWK$ shows the true network voltage prior to the control actions, the curve $ESTM$ shows estimated network voltage for the same abnormal condition and the curve $T&R$ shows the solution of controller. The controller increased the tap to 0.96 pu from 0.95 pu. Since the tap was limited at 0.96 pu and the cost of generation curtailment was larger than reactive compensation, the controller preferred to absorb 0.0431 MVAR of reactive power at node 51.

DISCUSSION

Segment control allows active control to be introduced with minimal disruption and extensions to infrastructure. As currently implemented, it is limited to control of voltage at a primary substation. The method can be extended to include local dispatch of distributed generation. However, the simple algorithm makes it unsuitable for a large interconnected network with many control variables.

Area control has the potential to use multiple control functions in a DMSC to control and regulate distribution network voltage. Its optimising methods allow it to control large interconnected systems, but it relies on key voltage measurements from within the network.

The practical implementation of the area control method is more complex than segment control. Since multiple control
functions are used, co-ordination between the controlled devices on the network is necessary. The control scheduler in the DMSC must know the order in which the control actions need to be executed when the OPF controller solution suggests multiple control actions.

These two control methods are therefore suitable for use in different types of distribution network. Segment control is appropriate for lower distribution voltages, e.g. 11 kV, where there is little measurement and communication infrastructure, few control possibilities and little interconnection. Area control is ideally suited for mid-level distribution voltages, e.g. 33 kV and 66 kV, with distributed generation, where there is currently little or no active management of the network but some infrastructure exists to provide it.

In the future both of these methods of control may co-exist, at different areas of the distribution network. They use very different control philosophies with the common theme being robust estimation of the network state.

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