NASPI Distribution Task Team
Technical Report

NASPI DisTT Use Case:

Phase Identification

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Use Case

The objective of Phase Identification is to recognize, track and report the connectivity and loading of Phases A,B,C through the distribution system so as to prevent excessive phase imbalance.

Background

Distribution system maps and models tend to lack reliable information about which single-phase laterals or individual customers are connected to which of the three phases. This connectivity information is not entirely static, since during restoration work such as repairs after a major storm, the phasing may be changed (deliberately or inadvertently). Historically, utilities have relied on manual notations from field crews about connectivity. In the absence of detailed records, owing to anecdotal reportings, an approximate balance – say, on the order of 10% difference in currents among phases – can usually be expected at the feeder head, but with no guarantees and occasional large departures.

Balanced phase loading is important for several reasons. First, note that due to finite source impedance, unbalanced loads will result in unbalanced voltages for three-phase customers on the network. This can physically damage three-phase motors, and may also interfere with the controls of three-phase inverters. ANSI standard C84.1 specifies balanced voltages to within 3% be provided by the distribution utility, while NEMA motor ratings may assume a more stringent 1% voltage unbalance.[1] Second, utility equipment on the distribution circuit, including protective relays and voltage regulation, may not operate properly or as expected under significant phase imbalance. This may lead to voltage magnitude violations on one or more phases, or nuisance tripping of protection. Finally, appropriate phase balancing is necessary to maximize asset utilization (e.g. transformer capacity) and minimize energy losses in the distribution network.

With increasing penetration levels of distributed resources such as solar PV generation and electric vehicles, there is an increased risk exposure – both in that a small number of customers on the wrong phase can suddenly have a greater impact on unbalance, and because more equipment is likely to be sensitive to such an unbalance. Today's conventional methods for phase identification either rely on GIS information, which is known to be subject to errors, or use dedicated phase identifier tools that are commercially available. These tools require phase reference nodes to be installed; the method is also impacted by transformer (delta-wye) phasing.

Examples

By measuring voltage phase angles directly, distribution measurements using micro-phasor measurement units (micro-PMUs) offer immediate visibility into phase identification and state characterization. In the simplest case as illustrated in Figure 1, phases are easily identified by 120^{o} rotation, with a very small separation of phase angle (on the order of a degree) between points on a distribution circuit. The three images show the voltage angles on each phase for a pair of locations separated by several miles on a 12-kV circuit.

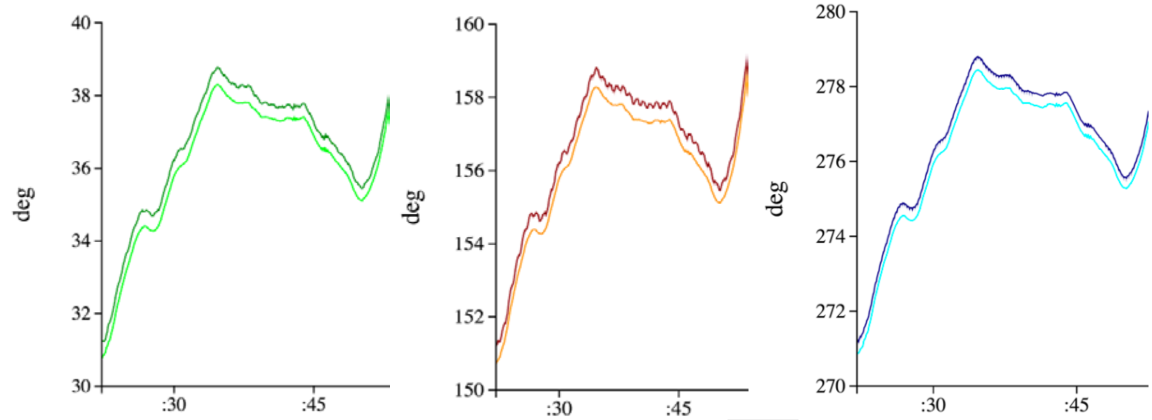

Figure 1: ABC phase alignment between two locations on a distribution circuit as seen by micro-PMUs on the Berkeley Tree Database (BTrDB) plotter (UC Berkeley, LBNL).

When locations are separated by one or more delta-wye transformers or lateral taps that introduce a 30° phase shift (making the phase association much less obvious), correlation between the time series signatures of voltage magnitude and/or angle can be used as an additional identifying tool. This is easiest during large asymmetrical disturbances. The example in Figure 2 shows voltage magnitudes and phase angles (relative to the same clock) during an event observed at two Bay Area locations, Berkeley and Alameda, separated by the 115-kV transmission network and multiple transformers. Without any network model information about the phase correspondence between these sites, we can confidently identify it based on the different shape of the angle disturbance for each phase (right), despite the matching phases being shifted by 180◦. We could have matched Phase A between the two locations based on the smaller per-unit magnitude of the voltage sag (left), but the association between Phases B and C by magnitude alone is less conclusive. Using PMU data obviates the need for specific equipment to actively inject a signal for phase identification.

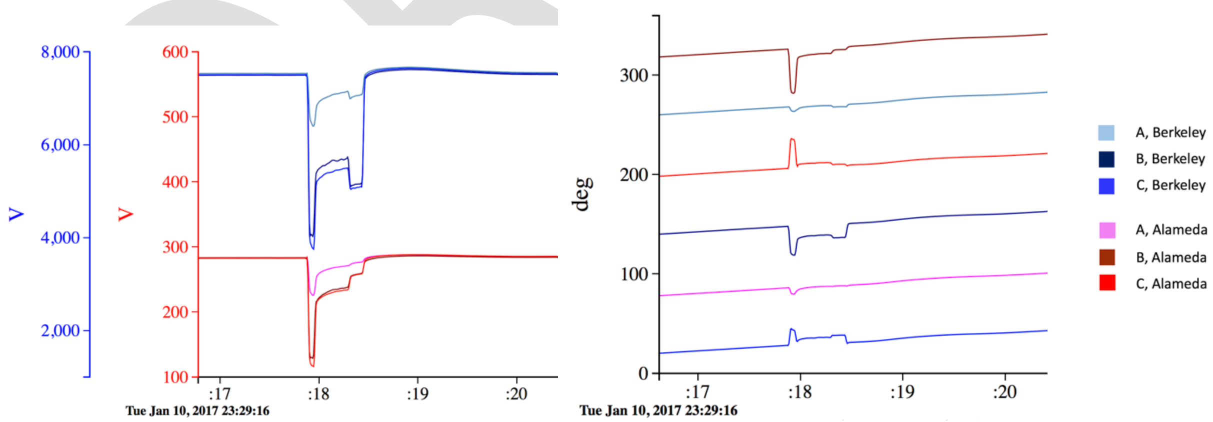

Figure 2: Voltage magnitudes and angles during a disturbance event at two locations separated by the transmission grid and multiple delta-wye transformers (UC Berkeley, LBNL).

Data Requirements

Phase identification relies on the comparison of synchronous voltage phase angle measurements, but is not sensitive to their absolute accuracy. Stable errors on the order of 0.01 p.u. or 1° of angle (such as those from instrument PTs transducers or even loaded service transformers) should not significantly impact this application, because of interest here are either steady-state offsets in the tens of degrees, or variability on a time scale of cycles to minutes (rather than days to months). A relatively short sampling window of data (e.g. minutes) with time resolution on the order of one sample per cycle should be sufficient. This use case requires micro-PMUs to be placed on exactly the circuit branch whose phasing is to be determined. Temporary sensor connection at the secondary voltage level may be an attractive option.

Development and Limitations

Tools and algorithms for this use case are at Technology Readiness Level (TRL) 6, ready for deployment in pilot-scale demonstrations.

References

[1] Pacific Gas and Electric information sheet on phase unbalance
http://www.pge.com/includes/docs/pdfs/mybusiness/customerservice/energystatus/powerquality/voltage_unbalance_rev2.pdf (accessed December 2016)