THIRD GENERATION MONITORING SYSTEMS FOR ELECTRIC POWER DISTRIBUTION NETWORKS LAY THE FOUNDATION FOR FUTURE SMARTGRIDS.

James NORTHCOTE-GREEN
PowerSense A/S - England
jng@powersense.dk

Martin SPEIERMANN
PowerSense A/S - Denmark
ms@powersense.dk

Jesper KLINGSTEN NIELSEN
PowerSense A/S - Denmark
jk@powersense.dk

ABSTRACT

This paper discusses present data availability for distribution networks and how increasingly this is inadequate for future management requirements of assets and operations, particularly as SmartGrids become a reality. The concept of a third generation distribution monitoring system (3GMS) that will satisfy both operational and asset management needs simultaneously is presented followed by the description of an actual 3GMS based on optical sensors and a smart communications front end. The paper concludes with a summary of an actual installation.

INTRODUCTION

Distribution automation has extended the reach of traditional SCADA systems beyond primary substation boundaries to included devices located down feeders. These devices include remotely operable switches (ring main units, overhead enclosed SF6 switches and airbreak disconnectors), capacitor and line regulator controllers and fault passage indicators. Data from all these devices, provided they have a communication capability, are made available to the central control system via some form of communication infrastructure. This infrastructure can vary across the service area from low power radio, fiber optics to mobile phone technology (GSM, UMTS etc.). The fundamental component of this data acquisition system is the intelligent electronic device (IED) that is mounted in every primary device to pass the data to the communication system and then to the SCADA front end. The potential for remote control at the feeder level together with more data for fault location has made it worthwhile to add more intelligent applications to the SCADA to create present day Distribution Management Systems (DMS).

The emergence of SmartGrids with distributed generation sources will impose the need to accommodate bidirectional power flows on today's DMS and data acquisition systems. These systems have been based on the general assumption that network structures are predominantly radial.

In parallel with the establishment of Distribution Management Systems for the real-time control of networks pressures have mounted on Asset Managers to better use and maintain present network assets that in the majority of systems have reached their amortized life which must now be extended due to economic practicalities. The performance of DMS data acquisition systems, having been designed for real-time operations, may be degraded should the additional data needs of asset management be superimposed.

In this paper the simultaneous needs of both operations and asset management will be explored which can be met by an IED that comprises a 3rd generation distribution monitoring system (3GMS). This IED will form the foundation of any new data acquisition system. Further such a system must be retrofittable to presently installed primary equipment.

DISTRIBUTION NETWORK STATE DATA

Unlike transmission networks data availability has always been one of the main limitations for most distribution systems stemming from, historically, a lack of consistent timely measured data and the coordination of that data with the asset data base. SCADA systems have enabled state data (switch positions and measurements) to be provided down to the substation level. The introduction of feeder automation (FA) as part of distribution automation initiatives has provided state data of a few switches outside primary substations (1 or 2 per feeder depending on the Automation Intensity Level – AIL [1]) and seldom any measurements. In addition fault location information is provided by Fault Passage Indicators (FPI) dispersed between automated switches and at these switches. The fault location logic using the FPI change of state data assumes that the feeders are radial and thus power flow is in one direction out of the primary substation. FPIs operate in a binary manner once a preset current threshold has been exceeded.
Data can be divided into a number of categories:

Topographical data

Provides network connectivity giving the actual structure of the distribution network in terms of cable and line runs together with the configuration of every substation. The location of the dynamic elements of the network particularly switches, are part of these data. The state of the devices is provided in two forms, "as built" and "as operated". The latter state is the most important since network operation will alter this state depending on the switching actions undertaken. This information is provided from SCADA and FA data acquisition system for remotely controlled (automated) devices and maintained in the control room on operating diagrams. Changes in the state of manually operated switches are noted by network operators on the same diagrams.

Load data

Provide these visibilities for operators to perform switching operations under planned and unplanned situations without overstressing the network. It is also the fundamental information that planners use to assess future loading levels and prepare reinforcement strategies for the network. This data is provided from the SCADA systems down to primary substations and MV feeder headers but little information from direct readings is available at load points down the feeder. Traditionally load information has been obtained from two sources (i) by reading of maximum demand meters at substations once or twice annually and (ii) by accumulating consumer kWH meter readings at MV/LV transformers that is converted to kW demand using an empirical relationship or local load factor. Present network analysis applications use all available measured data and through a calibration or state estimation process calculate missing values for the other load nodes in the network. This method inevitably suffers from significant errors and poor treatment of load diversity an important issue in accessing distribution equipment loading.

Network definitive parameters

These data describe each of the system elements in terms of type, impedance, ratings etc. used mainly to set operating limits and to make network calculations for DMS on-line and off-line planning applications. These data are considered static since they change only during construction or refurbishment and are maintained in asset registers within geographic information systems (GIS).

It is clear that an increase in the level of distribution monitoring (Monitoring Intensity Level (MIL) – the percentage of load locations monitored) will alleviate many of the present errors for load data but in addition improvements to fault identification could be achieved with actual directional fault current measurements.

DISTRIBUTION MONITORING EVOLUTION

First generation distribution monitoring systems were essentially for control using small FRTUs retrofitted to primary switches along feeders. These IEDs communicated directly back to one master SCADA at central control. They enabled opening and closing of the switches remotely and also the passing of certain alarms for health checking of the control cabinet (battery life, temperature, loss of voltage). Analogue measurements were not included for the reasons that primary CTs did not exist or their output was not accessible and the protocols were restricted to digital signals. The lack of primary current measurements is a draw back in extending first generation (1G) systems. Second generation (2G) monitoring systems started to take in signals from other ancillary devices such as FPIs and to communicate their operation back to the control room. Both first and second generation systems remained focused on real-time operation and providing operations data to the control room. Third generation monitors perform all the first and second generation functions but in addition produce timely load measurements on a continuous basis as required for Asset Management systems with the communication function to transmit appropriate data to different sources at selectable time intervals. The role of three generations of distribution monitors is summarized in Figure 1.

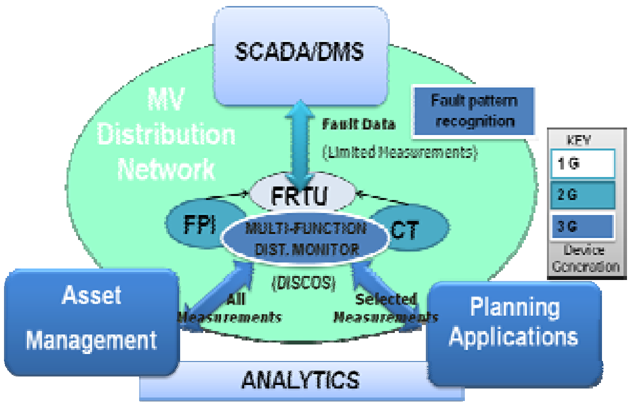

Figure1, 3G Multi-functional monitor replaces traditional earlier generation single device solutions (FPI, CT, FRTU) with a single integrated intelligent unit.

The key functional requirements that must be met by a 3G distribution monitor are as follows:

- Primary current sensor that can be noninvasively installed on MV cables and overhead conductors.
- LV current sensors for LV cables
- Intelligent electronic unit to:
  - Locate and identify faults of different types
  - Compute power quantities from current sensors and voltage measurements.
  - Process alarm and switch control signals
- Flexible and configurable communicate module able to selectively route information to different destinations at different intervals.

EXAMPLE 3G MONITORING SYSTEM

Third generation monitoring systems must integrate in a modular fashion many functions that previously have been provided by individual standalone non communicating devices. Such a system described here is comprised of the following modules that can be configured to meet specific application requirements of different areas of the distribution network.

Sensors

The optical current sensor provides an innovative cost effective solution for monitoring of the power network, particularly at the MV/ LV transformer stations. The ability to determine incoming and outgoing currents on both sides of the transformer, under normal and fault conditions, facilitates the location of outages and the management of the network asset. Traditional monitoring units rely on CTs for current measurement. They are limited under fault conditions by the saturation of the CTs. In contrast the optical sensor has 1-2% accuracy over the entire current range of 1-20,000amps (Figure 2).

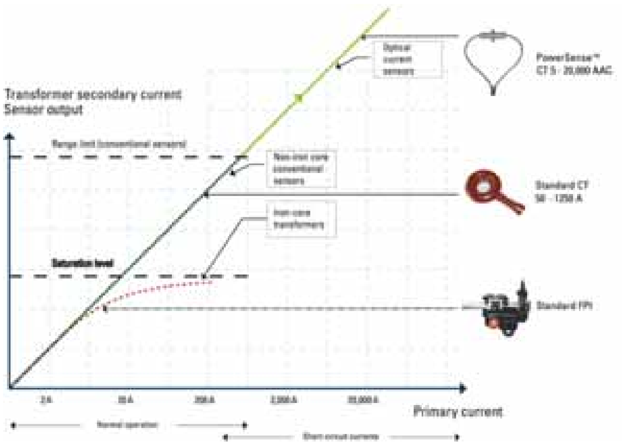

Figure 4, Linearity of Sensor response to current magnitude

Further the capability to measure all harmonics from the fundamental to the 50th is available for advance applications such as power quality measurement, earth fault identification in compensated networks and fault detection for fallen conductors in high impedance fault conditions.

Figure 2, Linearity of the primary to secondary current relationship of a temperature and ageing compensated optical sensor used in the DISCOS® distribution monitor.

The core of the monitor is the optical sensor which uses Faraday's effects. The light beams are interpreted by the optical unit which has the intelligence to compensate for temperature and aging variations, also to interpret the light signals into real amperes. This electronic module also calculates other power system parameters such as real and reactive power. Further network specific fault identification filters can be implemented to determine different types of fault such as short circuit, earth faults, open conductors and cross country faults. The sensor is installed noninvasively by strapping it to the outside insulation of any cable close to the termination in ring main units. Figure 3 shows a typical installation. Optical sensors can be cost effective for MV/LV transformer station monitoring provided the LV side cable/bus connection is accessible. In cases where monitoring of all LV feeders by phase is required split core CTs in conjunction with a special I/O module are preferred. The voltage reference required for making power quantity calculations is obtained from the LV bus of indoor substations through the LV Interface module.

Figure 3, Installation of cable mounted optical sensors

The overhead version is packaged with a voltage divider and clamp so that the entire sensor is self contained and the reference voltage is at the same point as the current measurement.

Switch Control

Sufficient digital I/O capability is integrated within the electronics of the monitor to allow complete control of any switch associated with the monitoring locations and also to pass any other alarms such as primary network fault occurrences and multi-health checks of the monitoring system.

Communications module

The final component is the communication capability that is specifically designed to stream selected data to different destinations as required by the particular application. A variety of different standard SCADA (DNP 3, IEC 60870-5-101/104, 61850 etc,) and Enterprise IT bus protocols (IBM MQTT/MQ Advanced Enterprise Service Bus (ESB) are supported and can be deployed through at least two communication channels using different communications media (GSM, CDMA, WIMAX, RS232) to fibre, wire or wireless). This Linux based module allows reconfiguration of the communications front end to accommodate customer specific requirements with relative ease. Data can be categorized as alarm data or asset data and streamed to different locations using an alternate protocol for each path.

CONFIGURATIONS

The various modules are integrated through a standard CAN bus and can be arranged depending on the solution. Examples of a variety of solutions presently in use are given in Figure 4.

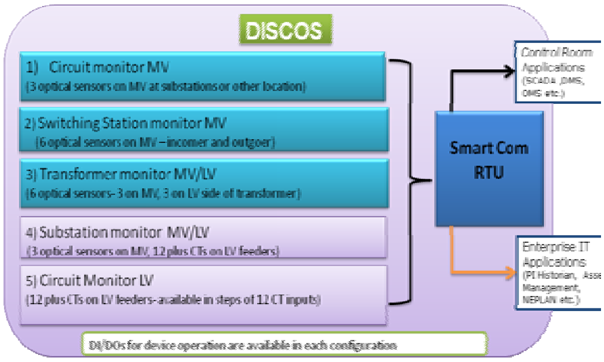

Figure 4; Five typical 3GMS Configurations

INSTALLATIONS AND EXPERIENCE

The complete monitoring solution described above is the DISCOS® monitor initially developed within the Danish utility industry and now supplied by PowerSense. Over the last 3 years 10,000 DISCOS®s sensors have been deployed at more than ten utilities worldwide. For example Reliance Energy in Delhi is trialling the solution at MV/LV substations. MEA, Bangkok has installed the OH version and successfully identified fallen conductors both up and down stream of the device. Energy Australia is in the initial phase of installation aimed at all MV/LV substations for complete monitoring of all LV feeders by phase with optical sensors on the MV incomer.

The most significant implementation of the DISCOS® system is at DONG Energy (Nesa) in Denmark where 250 MV/LV transformer stations (2,000 sensors) have been fitted and the results brought back to two applications through the IBM ESB. Figure 5 shows one typical display of the detail of information obtained.

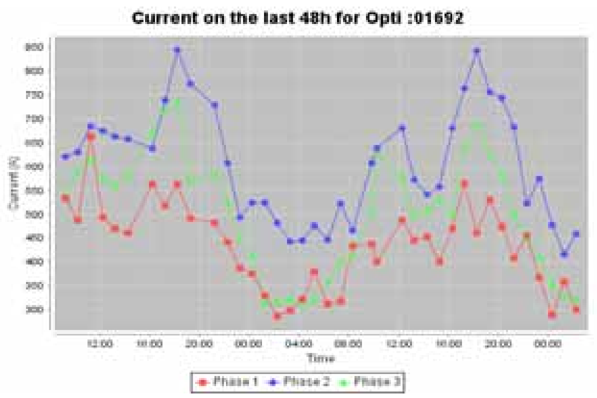

Figure 5, Typical phase current result showing unbalance

At DONG Energy (formerly Nesa) two types of DISCOS® have been installed. Type A included the control feature and was installed at switches capable of being retrofitted for remote control and Type B with monitoring only where it was impractical to convert the existing switching devices for remote operation. Benefits for an AIL of 7.5% and a MIL of 10% showed a reduction in energy not supplied by 50% and the fault location search time shortened by 35%. Addressing asset replacement or premature reinforcement the benefits gained from improved planning analysis were estimated to reduce reinforcement by 81-98%. The benefits analysis over a 20 year planning horizon showed a ROI within five years.

CONCLUSIONS

The experience at DONG Energy demonstrates the benefits and practicalities of the 3GMS architecture described in this paper. The key features of the device are the non invasive installation of the current sensor that allows retrofitting to existing primary plant, the linearity of the current measurement over a large range and the smart communication module. The capability to measure fault current and harmonics provides the opportunity to investigate the footprint of different types of fault that should eventually be used to identify these faults. Such research is in progress at some of the installations with optimism for success. The smart communications module not only allows two functional organizations within a utility with vastly differing data requirements to be served by one device, but it also accommodates the achievement of different monitoring goals under one communications and data infrastructure deployment. The benefits support deployment of 3G distribution monitors such as DISCOS®. They open the door for utilities to economically increase the level of MIL and provide the benefits derived from better knowledge of the actual loading levels of the MV and MV/LV substation assets. These benefits are immense for utilities with aged assets and will allow selective deferral of equipment replacement. The information will enable better planning leading to nearer optimal expansion of the network together with the ability to assess power quality issues and simultaneously achieve existing distribution automation benefits. 3GMSs also position utilities for the emergence of the SmartGrid.

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[2] James Northcote-Green, Martin Speiermann, Alfred Manohar, "Innovative Optical Sensor Technology the Foundation of Cost Effective MV/LV Distribution Network Monitoring" DA Conference, Bangalore, November 2007.