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Protection and Control of Active Distribution Systems

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SUMMARY

An **a**utonomous, **a**daptive and **S**ecure **D**istribution **P**rotection system (**a^{2}SDP**) for active distribution systems with any penetration level of PV and other DERs is presented. The system uses **E**stimation **B**ased **P**rotective (**EBP**) relays which are immune to the direction of fault current flow, level of fault currents, waveform distortion, lack of or reduced negative or zero sequence fault currents or any changes (topology or disturbances) outside the protection zone. The system provides a reliable solution to the three main challenges in protecting active distribution systems with high penetration of DERs: (a) low or varying fault currents and current direction, (b) changing topologies and characteristics as resources are switched in and out, and (c) reduced or lack of negative and zero sequence fault currents. **a^{2}SDP** has additional features that drastically increase the reliability of the protection and control system: (1) detection and self-healing against hidden failures, and (2) a robust solution to the well-known downed conductor problem of distribution systems.
The protection and control infrastructure presented in this paper, provides the enabling technology for the next generation of distribution management systems with additional functionalities: Feeder reconfiguration for real time optimization of the system operation, as well as feeder reconfiguration following a fault to maximize service (Fault Locating Isolation and Service Restoration (FLISR)). Distribution system wide dynamic state estimation at a rate of once-per-cycle provides full situational awareness for the entire distribution system. Many other applications can be added to this system in the future.
As with any new technology, testing and validation of the system requires new customized approaches for acceptance, factory testing, and field verification. For the proposed system, new approaches for testing and validation have been developed and evaluated: (a) testing of the sample value data concentrator, (b) synchronization of the sampled values obtained by merging units dispersed along the distribution system, (c) calibration of the merging units using advanced dynamic state estimation based methods. We present these testing methods for factory testing as well as for real time field testing.
The proposed a2SDP is being implemented at distribution systems of three partner utilities under the sponsorship by the DoE/SETO.

KEYWORDS

IEC61850, Active Distribution System, Estimation Based Protection (EBP), Coordination Free Protection, Estimation Based Calibration, Synchronization, Hidden Failures, Self-healing.

1. Introduction

Presently the distribution system is experiencing a transformation from a passive radial system to an active distribution system (ADS) with many customer and utility owned distributed resources. The US legacy PACS design has become vulnerable to relay misoperations; vulnerabilities are observed in transmission and distribution alike [1]. Protection for legacy US distribution systems has been designed under the assumption of unidirectional power and fault current flow. In ADSs this assumption is not valid anymore. The presence of inverter based resources creates new characteristics that affect both transmission protection as well as distribution protection. Specifically, IBR dominated systems are characterized by reduced fault current levels and reduced or absence of negative and zero sequence components of fault currents. Many protective relaying functions depend on the presence of high fault current levels containing negative and zero sequence components. These protection functions will be prone to relay misoperations. In addition, distribution systems are prone to high impedance faults, for example overhead distribution downed conductor faults, or contact with high impedance objects such as wet tree, and other similar scenarios. Many times, high impedance faults may draw almost zero current, as in the case of a broken phase conductor fallen on asphalt, dry soil, etc. We refer to this case as an *open conductor*. High impedance faults and open conductors are difficult to detect with existing technology. These conditions are protection gaps and constitute important challenges for ADS protection and control.

At the same time all ADSs around the globe need advanced protection and control systems to manage the system operation from the point of view of voltage control and system optimization. It is important to manage and control the abundant distributed energy resources for the benefit of the overall system. The alternative of ignoring the relevant issues will be a system with wild voltage variability and generally poor performance.

During any type of fault, the protection and control system must act to isolate the faulted part of the system. Since ADSs are radial, the clearing of a fault typically results in isolating the faulted part of the system plus parts that are healthy. It is desirable to restore power to all healthy parts by reconfiguring the resulting system. For automated feeder reconfiguration, one needs to know the location of the fault, the prevailing system operating conditions at the time of the fault, as well as the existing types of switches, breakers, reclosers, etc. The reconfiguration is achieved by a sequence of opening and closing breakers, switches, etc. until only the faulted component is isolated.

It is important to first address the protection of an ADS. This paper introduces the estimation based protection to provide a protection system that is immune to the new characteristics of an ADS. The paper describes a protection system for ADS that enables (a) a protection and control method that is fully immune to the ADS characteristics, and which detects hidden failures and cyber-attacks and can self-heal by replacing compromised data with estimated and validated data, and (b) an optimization and control method that addresses the operational needs of the active distribution system. It provides full situational awareness of the distribution system via a very fast high fidelity dynamic state estimation. Specifically, the dynamic state estimation is executed once per power frequency cycle, and it provides detailed three phase, neutral, and ground information. It is used to reconfigure the distribution system for the purpose of minimizing the number of affected customers following a fault. Furthermore, the protection system capabilities include fault locating, isolation and service restoration (FLISR), and system optimization under the prevailing operating conditions, at operator scheduled rates (for example once per 15 minutes).

2. Proposed Infrastructure and Protection of ADS

The proposed architecture of the **a^{2}SDP** is conceptually shown in Figure 1. The ADS is partitioned into several sections, each section maybe a few kilometers or a few tens of kilometers, and is equipped with a « node ». A node is a centralized protection and control system for one ADS section. The node equipment is contained in weather enclosures with communication links to the master node. The master node may be located in the substation, or anywhere where communication links are available.

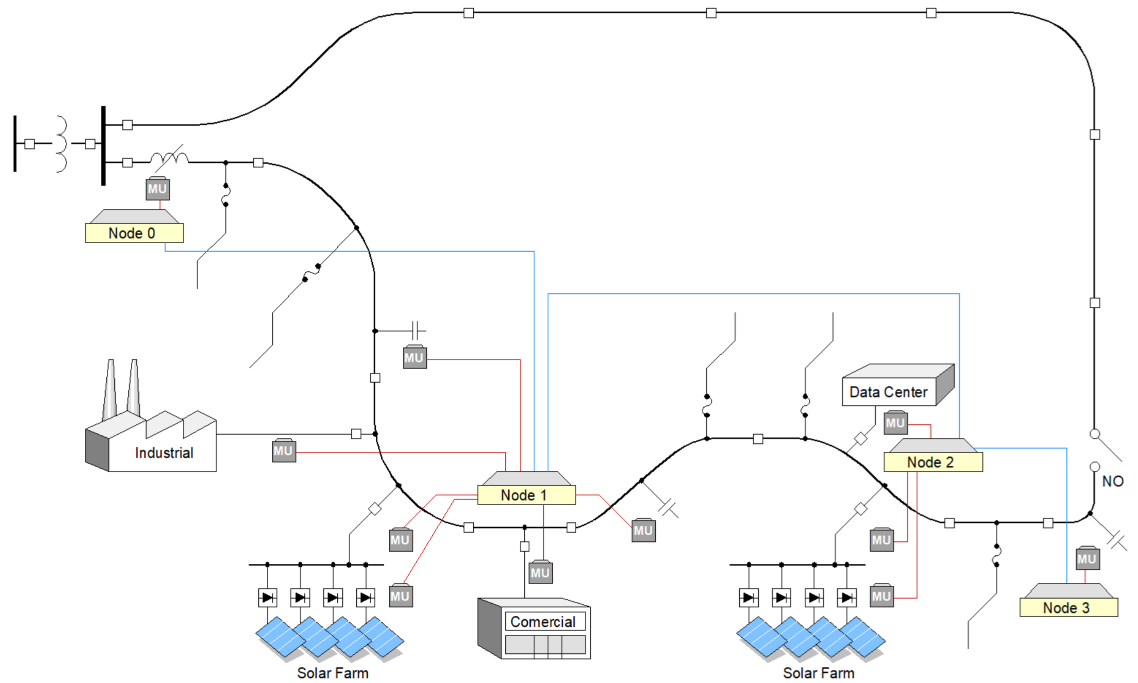

Figure 1: Basic Configuration of the a2SDP

The size of an ADS section, (the part of the ADS which is monitored by a single node), is user selected. For example, for a feeder with high concentration of loads and other resources, an ADS section may be just several miles of distribution lines. Sections containing less dense feeders may include considerably higher length of distribution circuits. For example, Figure 1 shows that node 1 includes two capacitor banks, one industrial customer, one commercial building and a solar farm, in addition to a number of residential customers along the circuit. The node monitoring and controlling equipment includes an Ethernet switch, a GPS receiver, and a computer. Seven data acquisition systems (merging units) are located along the feeder section. While other data acquisition technologies can be used, merging units are preferred to develop a process bus based data acquisition design since we believe that these will be the devises of choice for the near future.
The master node (Node 0 in Figure 1) collects data from all nodes and forms the model of the entire ADS, synthesizes the dynamic state estimation for the entire ADS and runs applications that affect the entire ADS. Detailed descriptions of the master node (Node 0) is presented in section 8.

3. Local Node Organization

The basic equipment at a local node are a GPS receiver, a network switch, a computer and an uninterruptible power supply (AC or DC). The merging units monitor system voltages and currents as well as switch and breaker status and other discrete data at various locations. Dual fiber-optic cables connect merging units and/or numerical relays to the local node. These connections continuously carry **S**ample **V**alue (SV) streams from merging units to nodes, and provide a sampling synchronization time reference to merging units via the precision time protocol (PTP). Synchronization issues are discussed in section 4. They also carry status data via GOOSE messages by exception. Tests resulted in the decision to use single mode optical fibers, since distances between merging units and node locations can exceed one kilometer.

A more detailed view of the local node is shown in Figure 2. The tasks of the node are: Merging Unit (SV) Data Concentrator (MUDC) from multiple merging units at variable distances from the local node. While SVs are synchronized with accuracy better than one microsecond, SV latency (i.e. the delay between sampling time and the time each sample appears on the process bus) is typically under 2 milliseconds. The MUDC manages the process bus: captures the sampled value packets generated by the merging units, time aligns, and buffers the samples for use by any number of applications. The process bus is organized into two redundant circular buffers (CB) which always retain the N most recent values received. Each application obtains the SV data as needed from the circular buffers.

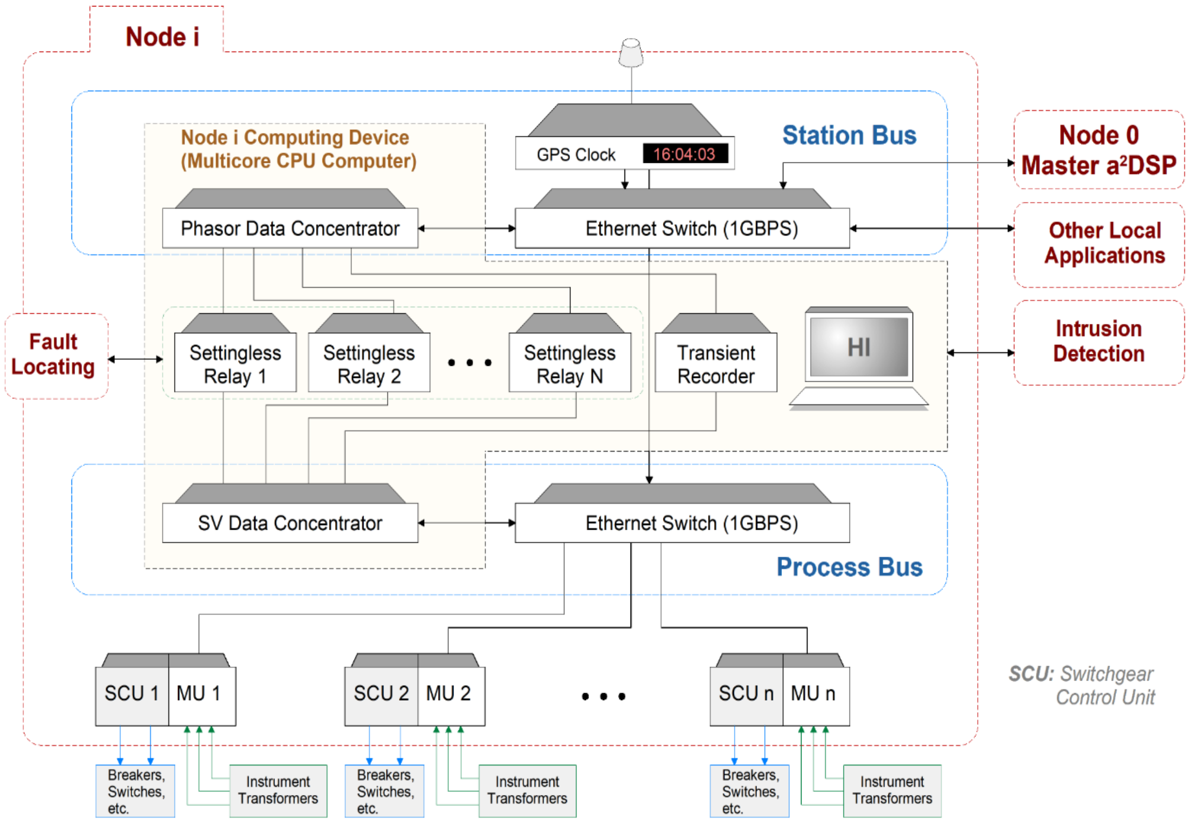

Figure 2: Basic Configuration of a Distribution System Node

The collected SV data are used by the various protective relays in order to perform the protection functions of all the protection zones in the node. Figure 2 shows settingless relays – as the preferable protection function implementation. This task is described in more detail in section 6. Note also in Figure 2, once a fault is detected, the fault locating function is activated. Another important task is to assess data synchronicity and data validity at each local node. This is discussed in section 7 and factory testing procedures and acceptance are described in section 10. The local node transfers voltage and current phasor data to the Master Node (Node 0) via the synchrophasor protocol (IEEE-C57-118) and status data via GOOSE messaging by exception, (see Figure 2). For proper real time operation, a multicore computer is connected to the switch via a wired Ethernet link. Each task is running in a separate computational thread. A multicore computer with enough cores is used to facilitate true parallel execution of all computational threads.

4. Synchronization via PTP

A protection and control system based on merging units should require that all measurements be synchronized with high accuracy, even if some people expressed a different opinion. We recognize that we do not know when and how the process bus data will be used and by what application throughout the life of the system. Thus, we propose to synchronize all the data in the process bus. This way, all applications, present and future, have available synchronized data. Testing methods for verifying synchronization accuracy are presented in section 10.

5. Calibration Issues

The new technology has many advantages, one of them it enables software based calibration procedures for highly accurate data. We implemented a software based approach for testing and correcting synchronization errors, magnitude errors and DC offset errors. The software based testing method is presented in section 10.

6. Protection and Control System

The core technology for the protection and control system for an ADS is the **E**stimation **B**ased **P**rotective relay (EBP) or setting-less relaying. EBP uses dynamic state estimation to assess the health of the protection zone that it monitors. EBP has been inspired from the differential protection function that uses current measurements at the perimeter of a protection zone and then determines whether the generalized Kirchoff's current law is satisfied, as shown in Figure 3. This approach makes coordination with any other protection function unnecessary. EBP uses all available measurements (high redundancy) to determine whether the measurements are consistent with ALL physical laws governing the operation of the protection zone. The best way to assess that all physical laws are satisfied is Dynamic State Estimation (DSE). DSE is a systematic and mathematically rigorous way to determine observance of all physical laws. ANY fault in the protection zone will manifest as a discrepancy between data and model resulting in a trip of the protection zone. By construction, the EBP relay is naturally the ultimate adaptive protective relay, immune to the new characteristics of IBR dominated power systems and free of the need to coordinate with any other protective relaying functions. We also refer to the EBP as the settingless relay because of the drastically reduced settings.

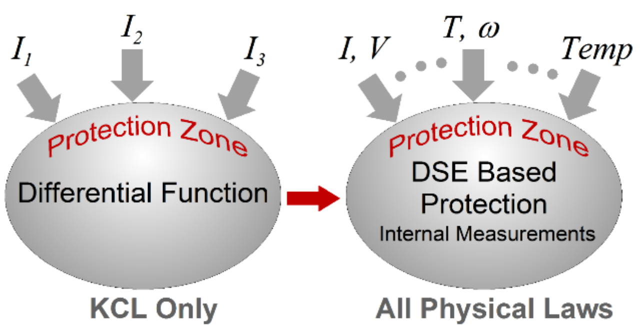

Figure 3: The Basis of the Estimation Based Protection

Each **EBP Relay** accesses the SVDC and retrieves the required SV data to perform the protection function for its protection zone. It requires the mathematical model of the protection zone, which is automatically provided by the software. Each **EBP Relay** module is executed on a separate parallel thread. Relay events resulting in breaker operations can in principle be transmitted to the merging units switchgear control unit via GOOSE messages. Presently, the system is set to allow the user to activate breaker control, or to suppress it and use the system for research and evaluation purposes.

EBP provides fast fault detection (sub millisecond) – as opposed to legacy protection that requires phasors (16 milliseconds minimum). No coordination with other relays is required which is a significant advantage. As mentioned, it is also immune to the new characteristics of IBR dominated power systems.

The EBP relay has been extensively tested for detecting and identifying downed conductors in the distribution system. The testing indicated that an EBP relay can detect a downed conductor with certainty. It does not provide the location of the down conductor, only the protection zone of the distribution system where a downed conductor has occurred, which is sufficient for reliable protection.

7. Other Local Node Functions

Fault Locating: Once a fault has been detected in any protection zone in the ADS, the a2SDP recalls the fault locating algorithm. It is a time-domain fault locating algorithm operating on the available measurements at the time, located in any point of the protection zone, and for the prevailing topology of the protection zone. Specifically, each measurement is expressed as a time domain function of the state of the protection zone and the fault location. The fault location becomes part of the state. Subsequently a dynamic state estimation algorithm is utilized to provide the best estimate of the state which includes the fault location.

Local Node Dynamic State Estimation and Data Validation: For this purpose, the **Phasor Computation Module** obtains the SVs from the MUDC circular buffer and converts them into phasors. The conversion is made via the "Standard-PMU" algorithm which computes phasors with high accuracy, using fundamental frequency tracking and quadratic fractional sample integration. Note that the phasor computations may be executed by multiple threads and that phasors are computed in real time. The desired phasor rate is one phasor per power frequency cycle. The computed phasors are stored in a circular buffer updated by a Virtual Phasor Data Concentrator (VPDC). At the same time the mathematical models of each protection zone, which are time domain models, are converted to dynamic phasor models, as shown in Figure 4. The phasors and the phasor domain models are used to formulate the dynamic state estimation for the entire node, automatically. We refer to this state estimator as the QSE to distinguish it from the state estimators run in each EBP relay. The solution of the QSE provides the best estimate of the state of the entire node and detects any anomalies in the data. In the case that

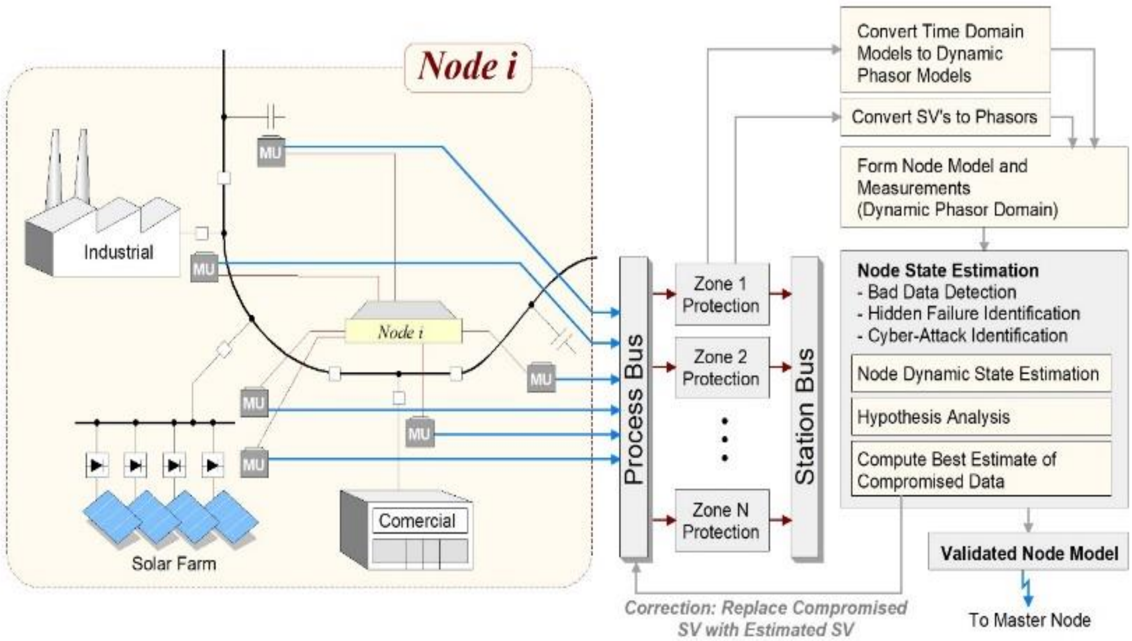

Figure 4: Architecture of a a^{2}SDP Node

data anomalies are found, a hypothesis testing algorithm is initiated to identify the anomaly. If the root cause of the anomaly is found to be a power fault, the relays are allowed to perform their function of isolating the faulty components. Other root causes are bad data, hidden failures and/or cyber-attacks and are treated accordingly. For example, in case of a hidden failure, a diagnostic message is transmitted to the operator for the purpose of sending a technician to repair the hidden failure; at the same time the compromised data from the hidden failure, are estimated and the estimated data are send to the process bus (the SVDC) to replace the compromised data. This is a reliable solution to the problem of hidden failures [3,4,5,6]. In summary, the local node performs the following basic functions: (a) collection of SV synchronized data, (b) Data validation, (c) Protection and Control for all protection zones of the distribution section using EBP relays. (d) protection against downed conductors, (e) fault locating, (f) SVs are placed in a centralized process bus (SVDC). Filling in occasional missing data with interpolated values. (g) SV are converted to phasors and time domain models are converted to dynamic phasor models for the purpose of formulating and solving the node dynamic state estimator, QSE, (h) Data anomaly detection and identification; in case of compromised data, replacement of the compromised data with estimated data to enable continuous operation of the system (resiliency), and (i) The phasor data and QSE results are transmitted to the master node.

8. Master Node Organization

The functional architecture of the master node (substation node) is shown in Figure 5. The hardware consists of a station bus, a PTP-enabled Ethernet switch with a local GPS clock providing the timing source, and a multicore CPU computer. The Ethernet switch permits communication with all the local a^{2}SDP nodes for the purpose of receiving phasors and node QSE results.

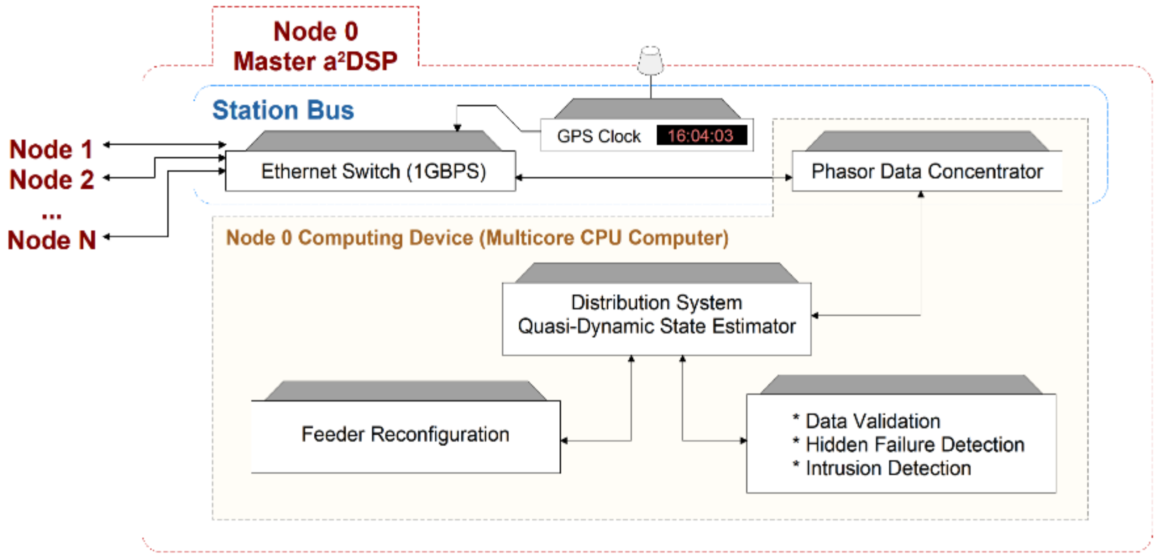

Figure 5: Architecture of the Master a^{2}SDP

The communication uses the IEEE C37.118/TCP-IP protocol. The multicore CPU computer executes a number of applications distributed in multiple parallel computational threads, and specifically: (a) Phasor Data Concentrator, (b) Formation of the entire ADS state estimator, (c) feeder reconfiguration for optimization or feeder reconfiguration to maximize service following a fault. At the master node, the incoming phasor data from the local nodes are stored in a Phasor Data Concentrator (PDC) for the entire ADS. The QSE results from each local node are used to synthesize the quasi-dynamic state estimation (QSE) for the entire ADS, as shown in Figure

6. This organization allows any application to be added at the master node. We discuss two applications in the next section. Others will come in the future.

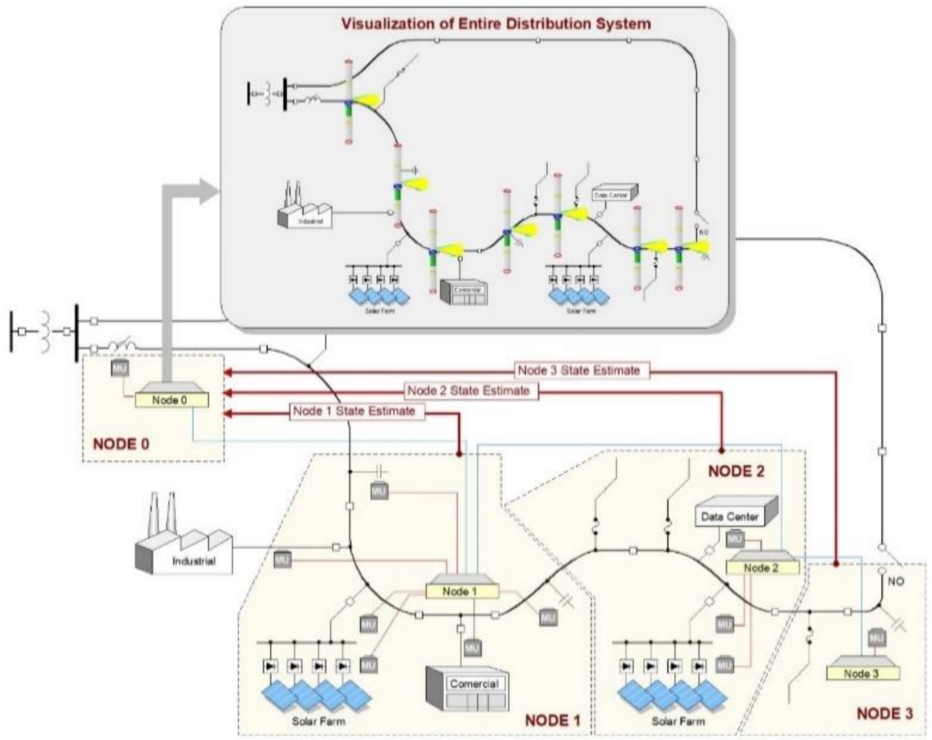

Figure 6: Dynamic State Estimation of the Entire Distribution System - Master a^{2}SDP

9. Applications: Optimal Feeder Reconfiguration and FLISR

Optimal operation of active distribution systems under normal conditions and the problem of fault locating, isolation and service restoration (FLISR) are mathematically similar problems. The proposed system for an ADS enables real time (automated) solution of this problem and real time implementation of the solution. Two problems are defined in [9]: (a) feeder reconfiguration to optimize operations under normal conditions, and (b) feeder reconfiguration to maximize service following the occurrence of a fault. We have formulated both problems as an optimization problem of the dynamic programming variety. In the first problem, the objective is to minimize losses or minimize operational cost, while the objective of the second problem is to minimize the number of interrupted customers. The solution for both problems is expressed in terms of an optimal sequence of switch control operations, subject to the operational constraints of the switches. Specifically, some switches must be deenergized before they open/close, other switches (breakers, reclosers) can interrupt fault currents and others can interrupt only load currents. The dynamic programming approach is very flexible and can integrate all pertinent operational constraints. Additional details are provided in reference [9].

10. Factory Testing, Acceptance and Field Monitoring

This is a new approach for ADS protection and control driven by the new technology of merging units and process bus as well as the estimation based protection. The method uses a broadcast process bus and station bus. Specifically, sampled values from all merging units are deposited on a process bus and all applications utilize the appropriate data from the process bus to perform their analytics. For this system, testing must verify the requirement that data are correct and synchronized. The testing method described here are deployable for factory testing as well as field testing. The testing method also goes one step further: if a discrepancy is detected, correction is applied, that is the method provides self-healing. The necessity of this approach became obvious from our experience with these systems. Specifically, these systems are implemented in a multivendor environment where different merging units exhibit different calibration characteristics. For example, one merging unit had a constant timing error of 142.6 microseconds (this was the most extreme timing error we encountered), various other merging unit had DC offset errors in the order of 5%. We also identified errors from the local instrumentation channels, including instrument transformer ratio errors, and errors due to long instrument wiring.

For these reasons, the developed software-based end-to-end calibration and synchronization method is a very useful and practical tool. A GPS based clock is used at each node, providing a time reference to each merging unit, transmitted via fiber-optic cable using the precision time protocol (PTP). In the event of a GPS signal loss, clock holdover capability is crucial and the hardware are tested to verify performance. The data acquisition system consists of merging units dispersed along the ADS. The testing described here measures the performance of PTP in devices located at different distances from the switch.

Factory Testing: Factory testing for this system is performed with hardware in the loop. Specifically, the cyber infrastructure of the system has been duplicated in the laboratory and has been tested for synchronization and calibration accuracy. The salient characteristic of the system is that a GPS receiver is located at each node, and merging units are connected to the system via long runs of fiber-optic cable, as shown in Figure 7. For factory testing, we provide a common input signal to a merging unit under test and to a reference merging unit and compare the generated sampled values (see paragraph titled "Laboratory Calibration of Reference Merging Unit"). The test merging unit is connected to the node switch via a pair of long fiber-optic cable. Example test results are shown in Figure 7. The merging unit under test was connected via fiber-optic cable of lengths up to 1,500 meters. The results of the test are reported as phase angle errors in a phasor diagram display (see right side of the Figure 7).

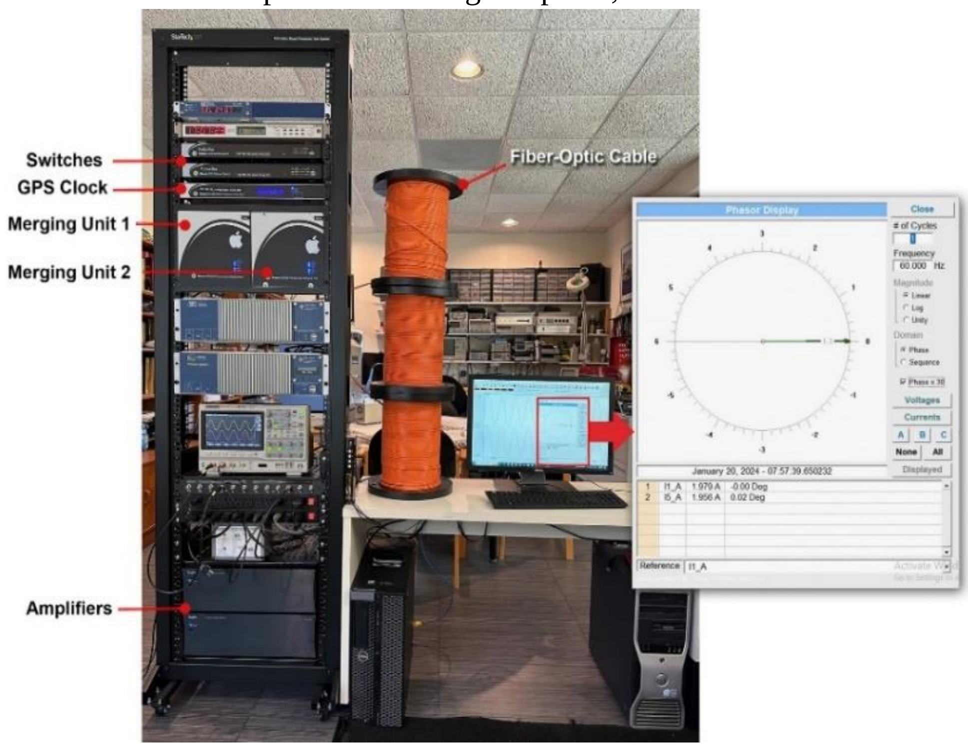

Figure 7: Factory Testing Setup

The reported phase error during these tests did not exceed 0.02 degrees, which corresponds to a timing error of less than one microsecond for all merging unit channels. This approach provides a practical test method to verify that the system of merging units connected via with long fiber-optic cables are accurately synchronized using PTP, and the sample-value time-tags are accurate to a microsecond. The tests typically run for a long time. An example timing error versus time test result is provided in Figure 8 for a period of 18.8 minutes. Note that the synchronization error is less than 0.5 microseconds for this test.

A similar approach is used to calibrate the system for correcting errors in magnitude and DC offset (see next paragraph).

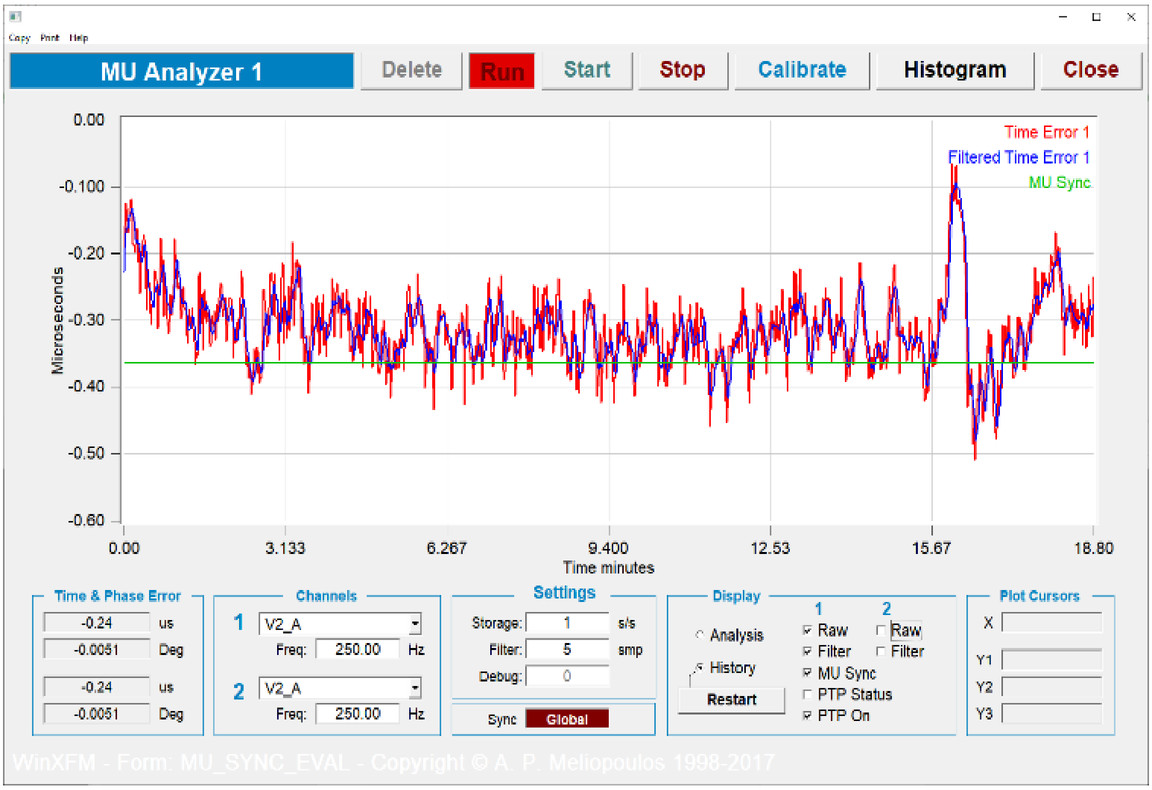

Figure 8: MU Synchronization History Over a Period of 18.8 minutes

Laboratory Calibration of Reference Merging Unit: Extensive laboratory work has been performed calibrating merging units to serve as reference units. We developed a tool which tracks the merging unit synchronization accuracy in real time. This tool requires that merging unit analog voltage inputs are connected to the output of a reference source providing a periodic signal of known frequency and constant phase with respect to the UTC time (A block diagram of this setup is illustrated in Figure 9a).

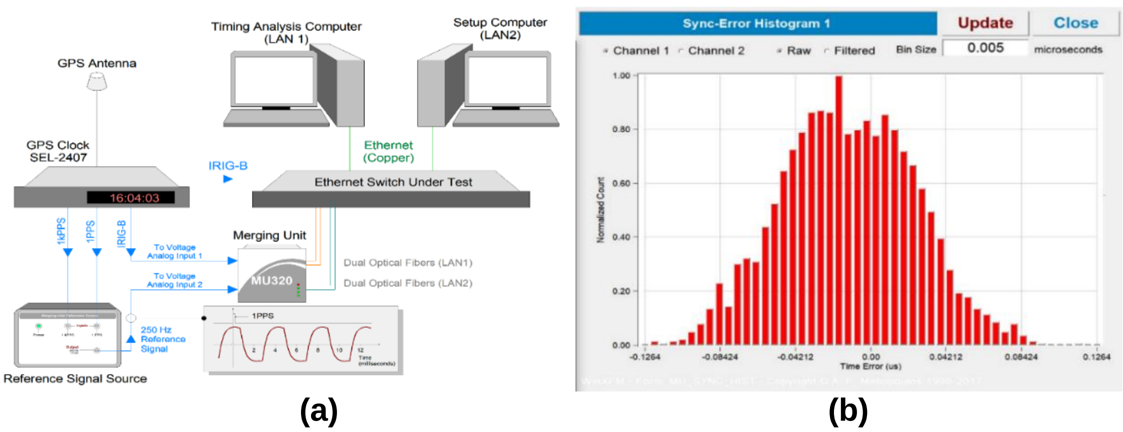

Figure 9: Merging Unit Synchronization Analyzer – (a) Setup Connection Diagram, (b) Error Histogram Window

Timing error analysis is performed simultaneously on multiple channels so that timing accuracy of different configurations can be compared. The fundamental frequency phasor of the captured waveform is computed by the method of rotating phasors. The timing error is computed by comparing the known phase angle of the reference source signal and the computed phase angle of the phasor. The timing error is presented as a function of time and in histogram form (see Figure 9b). Note that the timing error can be measured with accuracy of a fraction of a microsecond.

Field Monitoring of System Health: For field monitoring of sampled value synchronization, magnitude accuracy and DC offset accuracy, accurate measurements of the input signals to merging units are not available. For this reason, we developed a method that retrieves this information from the dynamic state estimation. Specifically, the dynamic state estimation described in section 7 provides the best estimate of each measurement and the expected error of each measurement. This information is used as the reference. This reference is compared to the measurement received from the merging unit under test yielding the timing, magnitude, and DC offset errors.

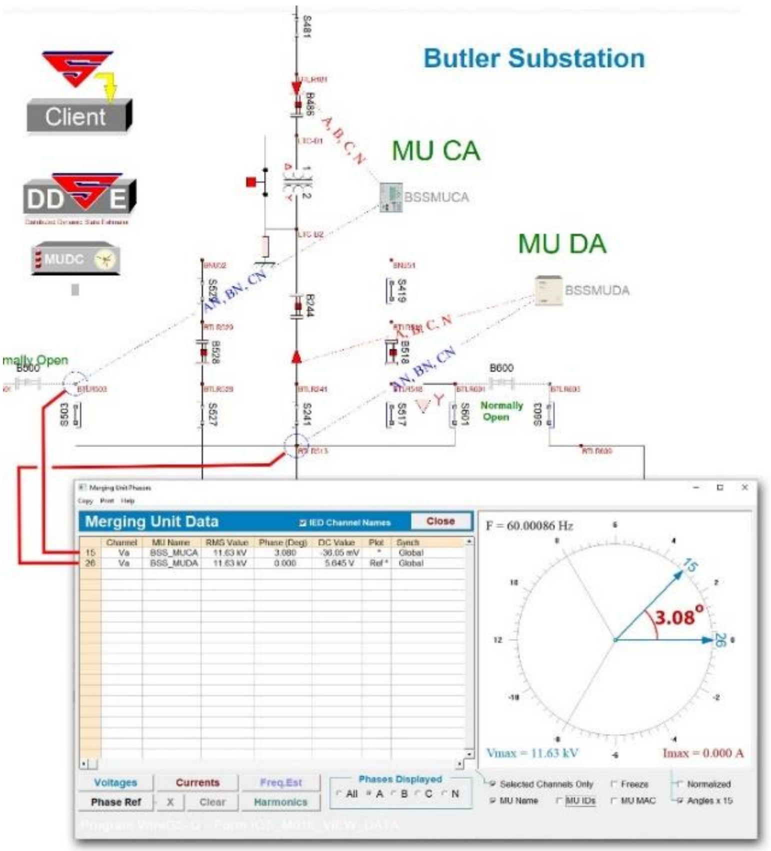

Figure 10: Time Synchronization Error Report

As an example, Figure 10 provides the phase angle error in degrees for a channel of an actual merging unit in the field (note the error is 3.08 degrees or 142.5 microseconds). Another report window provides all the errors (magnitude, synchronization and DC offset error) as shown in Figure 11. Note the user interface allows the user to apply the calibration constants manually for each measurement and verify the results of the calibration. In summary, the software based calibration is performed as follows: First, the dynamic state estimation for the node is performed. The dynamic state estimation also detects and identifies bad data and the best estimate solution represents validated data with known accuracy. The results of the dynamic state estimation are used as reference to provide the best

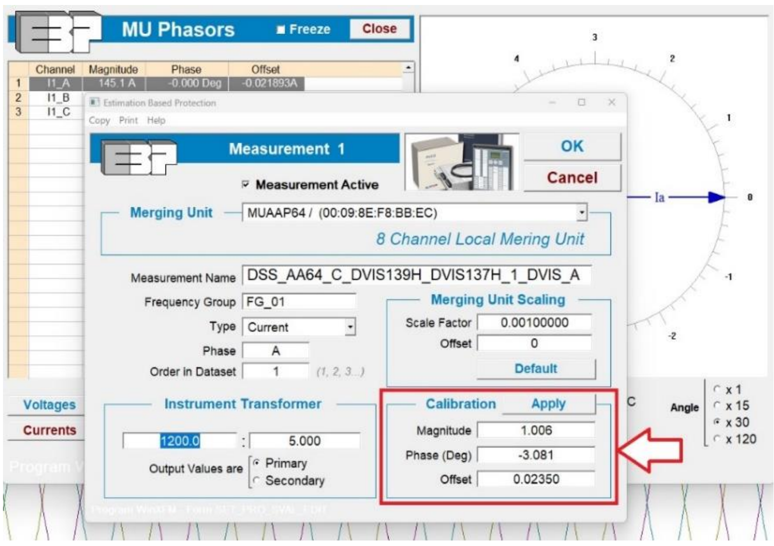

Figure 11: User Interface for Computing Calibration Factors

estimate of the errors of the identified bad data. The system can automatically perform calibration for all bad data or allows the user to do so one bad datum at a time and visualize the results of the calibration.

The use of calibration factors to correct specific measurements is simple for magnitude error correction (a simple multiplication), as well as DC offset error correction (a simple addition). The use of calibration factors for measurement synchronization error correction is a bit more complicated. Specifically, it requires an interpolation process to define samples occurring at the same time instances at all channels, i.e.: equally spaced samples with the first sample of each second occurring at the UTC time turn of a second.

This is a software based real time testing method. This approach has achieved excellent synchronization (accuracy better than one microsecond) for a system with merging units at different distances from the digital switch, as well as accurate magnitude and DC offset calibration. The importance of this work is also that the testing can be done in real time in the field (software based testing) to assess the installation and make field corrections, if necessary.

CONCLUSIONS

We have described the a2SDP system, a new approach for the next generation of a distribution management system, based on IEC 61850. The system provides a reliable protection and control system and immune to the characteristics of ADS dominated by IBRs.

Testing methods, customized for the new technology have been developed. The testing methods apply equally well for factory testing as well as for field health monitoring of the proposed system and for identifying, quantifying, and correcting calibration and synchronization errors. The testing methods continuously monitor the health of the system. The proposed system is being installed on active distribution systems of three utilities containing utility size PV systems, ranging from 2 MW to 20 MW, as well as other DERs.

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