Application of the SuperCalibrator as a Distributed State Estimator – Experience in Actual Systems

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Abstract

The SuperCalibrator concept was introduced to take advantage of the characteristics of GPS-synchronized equipment (PMUs). Specifically, GPS-synchronized equipment has the capacity to provide precise phase measurements (to 0.01 degrees accuracy) and relatively good quality magnitude measurements (up to 0.1% accuracy). However in a practical environment this precision is not achieved for a variety of reasons, such as errors from instrumentation, system unbalanced conditions, etc. The SuperCalibrator concept is based on a statistical estimation process that fits GPS-synchronized measurements and all other available standard data into a three-phase, breaker-oriented, instrumentation inclusive model. In this paper, this concept has been extended to provide a decentralized state estimator for power systems. The decentralized state estimator operates on substation data. The resulting substation state estimate is globally valid as long as there is a valid GPS-synchronized measurement at the substation. The paper describes the SuperCalibartor methodology. Presently the concept is implemented on five substations. Two of the substations are interconnected with a 765 kV transmission line. The implementation of the SuperCalibrator in these two substations will be discussed and numerical experiments will be presented. Because the two substations are interconnected the results of the SuperCalibrator can be directly compared to the state estimator of the two substations together, thus providing an excellent validation procedure. The implications of the overall approach are substantial. The SuperCalibrator applied to substations provides a decentralized, highly reliable and robust state estimator for large power systems.

Keywords: GPS-synchronized Equipment, Data Accuracy, State Estimation, Remote Calibration

Glossary

GPS: Global Positioning System
PMU: Phasor Measurement Unit
CT: Current Transformer
VT: Voltage Transformer
CCVT : Capacitor Coupled Voltage Transformer

1. Introduction

The need for synchronized measurements has been evident since the early days of electric power systems. Synchronized measurements require a precision clock that is globally available. The deployment of the Global Positioning System provided such a clock with precision better than one microsecond initially and presently 0.1 microsecond precision. Several efforts to develop synchronized measurements for power system applications have been reported. The first two authors reported in 1991 the time vernier method for time-tagging measurements obtained by a high-end fault recorder with precision 2 microseconds [1]. As a matter of fact, a prototype was constructed and tested. At the time this was the only available technology with precision of 2 microseconds or better. The PMS system developed by Phadke in the 1990-92 time period had a very large time error (or phase error) because the design included an analog antialiasing filter with a very low cutoff frequency (the design also used multiplexing which introduced additional time latencies). In January 1992, Jay Murphy of Macrodyne introduced a GPS synchronized data acquisition system and he was the first to name his device Phasor Measurement Unit (PMU). Jay Murphy's innovations included individual data acquisition channels all synchronized to the same clock signal (no multiplexing), a delta-sigma analog to digital converter (16 bits) operating in frequency of several megahertz, optically isolated inputs and A/D conversion and a front end that did not introduce any appreciable phase shift. The authors contacted tests on this unit in late 1992 and determined that the precision of the Macrodyne PMU is better than 0.02 degrees at 60 Hz (or alternatively the time precision is better than 1 microseconds) and 0.1% for the magnitude. Most of the recently introduced GPS synchronized equipment (with some exceptions) has similar characteristics. Thus, most PMUs provide measurements that are time tagged with precision better than 1 microsecond and magnitude accuracy that is better than 0.1%. This potential performance is not achieved in an actual field installation because of two reasons: (a) different vendors use different design approaches that result in variable performance among vendors, for example use of multiplexing among channels or variable time latencies among manufacturers result in timing errors much greater than one microsecond, and (b) GPS-synchronized equipment receives inputs from instrument transformers, control cables, attenuators, etc. which introduce magnitude and phase errors that are much greater than the precision of PMUs. For example, many utilities may use CCVTs for instrument transformers which may introduce errors as high as 5% in normal operating conditions and much higher in transient conditions. We refer to the errors introduced by instrument transformers, control cables, attenuators, etc. as the instrumentation channel error. Therefore early claims that touted PMUs to be able to measure the state of the system accurately and directly can not materialize without further developments.

Standards that determine what the accuracy of the phase measurement should be do not exist. We argue that the accuracy of the phasor measurements should be such that the error in predicting the power flow should not exceed 1%. If we consider a 50 mile long 230 kV line, rated 400 MVA and evaluate the precision in voltage magnitude and phase angle measurements required to achieve a 1% accuracy in power flow then we have the following pairs:
Voltage Magnitude: 0.5%, Phase Angle: 0 degrees
Voltage magnitude: 0.4%, Phase Angle: 0.03 degrees
Voltage magnitude: 0.3%, Phase Angle: 0.05 degrees
Voltage magnitude: 0.2%, Phase Angle: 0.09 degrees

Similar analysis could lead to a desired standard. Ignoring other sources of error, most GPS synchronized devices have the capability to measure voltage magnitude with precision 0.1% and the phase angle with precision 0.02 degrees. In this case the expected error in the power flow for the above mentioned line will be: 0.34%. Unfortunately, this precision cannot be achieved because of the other errors that have been mentioned. A year ago we reported on a new concept for correcting for these errors. We introduced the concept of the SuperCalibrator. The SuperCalibrator concept provides a practical approach for correcting the errors arising from instrumentation channels in a practical application. In this paper we propose the use of the SuperCalibrator as a practical and highly precise distributed state estimator. Specifically, the SuperCalibrator is applied at the substation level to provide the substation state which is globally valid if there is a valid GPS-synchronized measurement in the data set. This paper describes these recent advances and the planned demonstration of the approach on five substations.

2. Description of the SuperCalibrator

The SuperCalibrator is conceptually very simple. The basic idea is to provide a model based correction of the errors from all known sources of errors. Specifically, the basic idea is to utilize a detailed model of the substation, (three-phase, breaker oriented model, instrumentation channel inclusive and data acquisition model inclusive.) Then the measurements obtained with any device, PMU, relay, SCADA etc is utilized in an estimation method that statistically fits the data to the detailed model. Note that the proposed approach leads to a distributed state estimation procedure performed at the substation level. Since PMU data are utilized, the resulting estimates are GPS synchronized with the same precision as the PMU data. Note that distributed state estimation has been extensively addressed in the open literature. The approaches have been focused on the computational issue and they exploit decomposition techniques such as Dantzig-Wolfe and diakoptical methods. Our approach here is totally different and it is based on our previous work (e.g., [1-4]). We propose here a new distributed approach that can be characterized as a state measurer. For practical reasons, we propose an implementation where each subsystem consists of a single substation. This does not exclude defining a subsystem as a set of geographically adjacent substations and the circuits among them. It is assumed there is at least one PMU or GPS-synchronized relay in each subsystem. The methodology consists of the following procedures: (a) perform state estimation on each subsystem using all available data from SCADA, relays, PMUs, meters, etc. and a three-phase breaker-oriented, instrumentation inclusive model, (b) perform bad data identification and rejection as well as topology error identification on each subsystem, (c) perform alarm processing on each subsystem to identify root cause events, and (e) solve seams problems for the overlapping parts of the subsystems (state estimation coordination). Note that part (a) is based on the "SuperCalibrator". It is recognized that certain PMU measurements (PMUs from various vendors have been evaluated and tested earlier) provide much more accurate phase measurements from magnitude measurement. To take advantage of this fact, the proposed state estimator is not based on the total vector error defined in the standards (IEEE Std C37-118) but rather on a segregated magnitude and phase error. The overall performance of the state estimator is assessed with two approaches: (a) using statistical analysis of the state estimator results, such as the chi-square test, evaluation of standard deviation of estimated states and estimated measurements, statistical properties of residuals, etc. (b) by comparing the subsystem state estimate to the system state estimates using again statistical properties. The combination of these techniques quantifies the precision of the distributed state estimator. While the output of the SuperCalibrator is a three-phase estimate, in order to maintain compatibility with other applications, the positive sequence model and analog values are also provided by simply applying the symmetrical component transformation on the estimated three-phase model. This is indicated in the functional description of the approach in Figure 1. Note that the first output is the positive sequence of the estimated states. The figure also shows the data input to the proposed estimator. It is important to recognize that the next generation of substations will have standards such as the IEC 61850 which will make available all the data from relays, PMUs, SCADA, meters, etc on a common bus accessible from any other device. In this case the proposed system will simply access the 61850 bus to retrieve the data and perform the estimation.

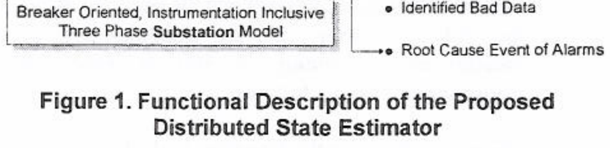

Figure 1. Functional Description of the Proposed Distributed State Estimator

The SuperCalibrator also facilitates sharp bad data detection and identification, alarm analysis and root cause identification. We use the term "sharp" to refer to the ability of the methodology to detect data that have high errors (for example 4%) that are not detectable by present day centralized traditional state estimators. This is achieved for two reasons: (a) at the substation level there is greater redundancy of data (as well as three-phase data) than a typical centralized state estimator. This redundancy facilitates the detection of bad data and system topology errors. (b) the state estimator problem is much smaller in size and makes the use of hypothesis testing practical. Hypothesis testing is a well known powerful method that identifies topology errors as well as bad data (data with high errors). Note that comprehensive hypothesis testing in centralized state estimators is a practical impossibility because of the large number of hypotheses and the size of the system. The use of the three-phase breaker-oriented model facilitates the identification of symmetric and asymmetric topology errors (one pole stuck, etc.). Note that traditional symmetric state estimators cannot identify asymmetric root cause events (for example stuck breaker pole). The proposed state estimator model, however, can identify asymmetric events with a direct approach.

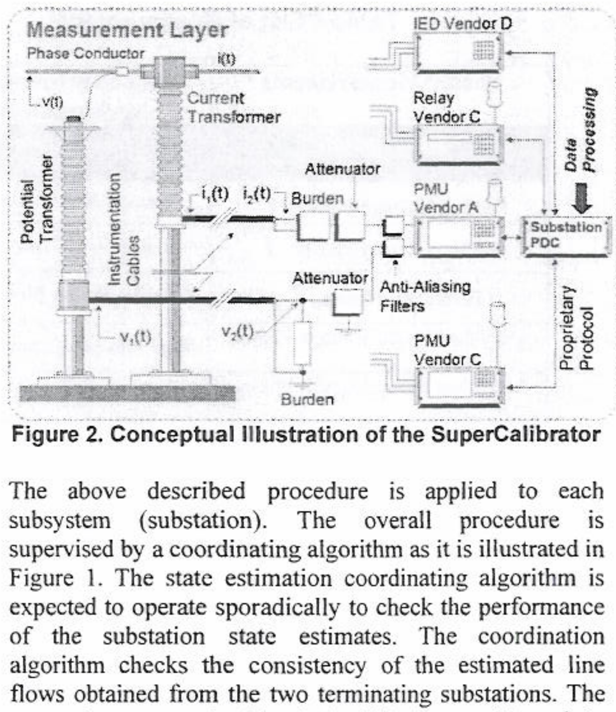

Figure 2. Conceptual Illustration of the SuperCalibrator

The above described procedure is applied to each subsystem (substation). The overall procedure is supervised by a coordinating algorithm as it is illustrated in Figure 1. The state estimation coordinating algorithm is expected to operate sporadically to check the performance of the substation state estimates. The coordination algorithm checks the consistency of the estimated line flows obtained from the two terminating substations. The two estimates must be identical within the precision of the distributed state estimator. If there is discrepancy the state estimation coordination algorithm is exercised. This algorithm is similar to the distributed state estimator except now the subsystem may contain several substations

3. Substation Level State Estimation

The SuperCalibrator filters instrumentation and other measurement data errors with state estimation methods applied at the substation level. We describe a method that is general and it can accommodate any available data. To introduce the method, consider the circuit diagram of the substation of Figure 3. The state of the system is defined as the minimum number of independent variables that completely define the state of the system. For a typical substation the state variables will the phase A, B and C voltage phasors on all buses of the substation. This is a relatively low number of states. The total number of measurements available in a typical substation from PMUs, relays and SCADA will be many times this number.

3.1 Measurement Data Set

The measurement types supported are classified into (a) GPS synchronized measurements and (b) non-synchronized measurements. A partial list of measurement types is given in Table 1.

Table 1 List of Measurements

Phasor Measurements	Non-Synchronized Measurements
Description	**Description**
Pos Seq Voltage Phasor, $\tilde{V}$	Voltage Magnitude, V
Pos Seq Current Phasor, $\tilde{I}$	Real Power Flow, P_f
Current Inj. Phasor, $\tilde{I}_{inj}$	Reactive Power Flow, Q_f
Individual Phase Voltage Phasor	Real Power Injection, P_{inj}
Individual Phase Current Phasor	Reactive Power Inj., Q_{inj}

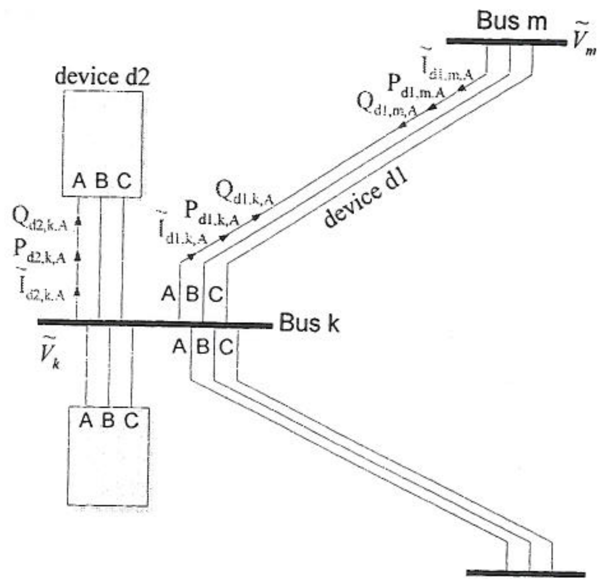

Figure 3 Measurement Definition – Three Phase Model

The measurement set may be phasors of individual phases, the positive sequence phasor, etc. Figure 3 illustrates the types of three phase measurements that may be available. Since at each bus the model may have a neutral node as well as a ground node, the measured phase voltages are always considered as the phase to neutral voltages.

Each measurement is related to the state of the system via a function. The SuperCalibrator recognizes that the instrumentation used to obtain a measurement is not ideal and includes the model of the instrumentation in the estimation process. As an example consider the voltage instrumentation channel illustrated in Figure 4. This is a wound type VT. The model illustrated in Figure 4 represents the non-ideal characteristics of the instrument transformer (in this case the Voltage Transformer – VT), the non-ideal characteristics of the instrumentation cable, the input impedance/signal conditioning unit of the relay, PMU, meter, etc. and the A/D converter model. The A/D converter model is represented with the digitizing unit (for example 12, 16 24 bits) and the digital output filter depending on the design of the device. The figure also illustrates the fact that meters can be placed at any position of the instrumentation channel to obtain the voltage phasor value at that point (Voltage Meter) and/or the phasor current value (Current Meter). The figure shows that there are two voltage meters in this example, one at the input of the instrumentation channel and another one at the input of the A/D converter. As an example, for a specific measurement assuming a 500 ft long cable, the measurements are as follows:

Phase A voltage on the line side: 62.53 kV, 27.52 degrees

Phase A voltage on VT secondary: 107.69 V, 27.51 degrees
Phase A voltage at PMU input: 106.72 V, 27.11 degrees
Phase A voltage at PMU output (digital): 106.61 V, 27.09 degrees.

Note that the overall introduced error by the entire instrumentation channel including the PMU is 0.43 degrees and 0.97 kV (or 1.46% of nominal). This error is computed by considering the instrumentation channel ideal with a gain of g=115/66,400. Note that the instrumentation channel error is much larger than the error introduced by the PMU alone. This is a typical case.

In addition, the operation of the instrumentation channel can be shown in an animated way by using the Instrumentation Channel Animation tool (shown in Figure 4 as "IC Animator"). When this tool is selected, the voltages at various points of the instrumentation channel are illustrated in an animated way including the differences (errors) from an instrumentation channel having the same parameters (transformation ratios) but ideal devices. More information is provided in [6].

The instrumentation error is modeled by simply relating the measurement (output of the IED) to the state of the system via the non-ideal gain of the instrumentation channel including the IED model. In general this is expressed as follows:

GPS synchronized measurements:

$$z_{rj} + jz_{ij} = g_j(x), \textit{ for measurement } j$$

Non-synchronized measurements:

$$z_k = g_k(x), \textit{ for measurement } k$$

This approach requires that the instrumentation channel be modeled and the gain (function g) of the instrumentation channel be computed. In general the gain function is a complex one.

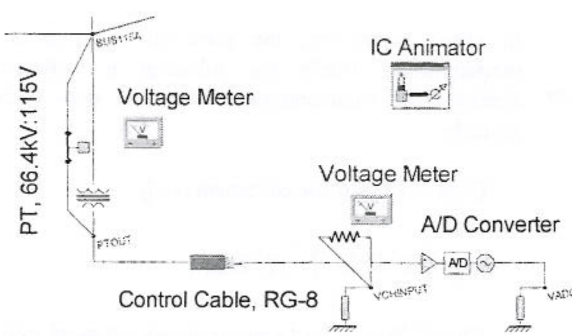

Figure 4. Computer Model of a Voltage Instrumentation Channel, PT Based

The above measurements are related to the state of the system via the "model" equations. As system state we consider the voltage phasors at all nodes of the substation, i.e. the three phase voltages at all buses of the substation, the neutral node voltage as well as the ground node voltage.

First the state of the system is defined as the node voltage phasors at each node of the substation. A bus k will have three to five nodes, phases A, B and C, possibly a neutral and possibly a ground node. The state of the system at this bus is the node voltage phasors. We will use the following symbols (for a four node bus, i.e. phases A, B, C and neutral N).

$$\begin{aligned}
\widetilde{V}_{k,A} &= \widetilde{V}_{k,A} = V_{k,A,r} + jV_{k,A,i} \\
\widetilde{V}_{k,B} &= \widetilde{V}_{k,B} = V_{k,B,r} + jV_{k,B,i} \\
\widetilde{V}_{k,C} &= \widetilde{V}_{k,C} = V_{k,C,r} + jV_{k,C,i} \\
\widetilde{V}_{k,N} &= \widetilde{V}_{k,N} = V_{k,N,r} + jV_{k,N,i}
\end{aligned}$$

The state for a four node bus k will be defined as follows:

$$\widetilde{V}_k = \begin{bmatrix} \widetilde{V}_{k,A} \\ \widetilde{V}_{k,B} \\ \widetilde{V}_{k,C} \\ \widetilde{V}_{k,N} \end{bmatrix} = \begin{bmatrix} V_{k,A,r} + jV_{k,A,i} \\ V_{k,B,r} + jV_{k,B,i} \\ V_{k,C,r} + jV_{k,C,i} \\ V_{k,N,r} + jV_{k,N,i} \end{bmatrix}$$

It is also important to note that normally measurements of neutral or ground voltages are not available. On the other hand these voltages are very small under normal operating conditions. For this reason, we introduce one pseudo-measurement of voltage phasor for each neutral and ground node in the system. The value of this measurement is exactly zero.

3.2 Segregated Magnitude and Phase Error

PMU measurements have the following characteristic. The magnitude error is typically different than the phase error. For most PMU units, the phase error is much smaller than the magnitude error. Utilizing the total phasor error results in missing information and compromises the performance of the SuperCalibrator. Within the formulation of the hybrid state estimator, the phase and magnitude errors are segregated by simply introducing an additional datum. This datum is treated as a pseudo measurement. The definition of the pseudo measurement is:

$$z_{pseudo} = (\tan(\delta))\operatorname{Re}\{\widetilde{V}\} - \operatorname{Im}\{\widetilde{V}\} + \eta$$

The standard deviation of the error η depends on the characteristics of the PMU. It expresses the error of the phase measurement. This formulation segregates the magnitude and phase errors of PMU data.

3.3 Hybrid Three-Phase State Estimator

This section presents the hybrid three-phase state estimator. This state estimator uses standard SCADA data, GPS synchronized data and relay data together with a full three phase system model to perform state estimation. The mathematical procedure is described next.

The measurements are assumed to have an error that is statistically described with the meter accuracy. The present state estimator supports the measurements that are listed in Table 1. Each one of these measurements has the following mathematical model.

Phasor measurements:

$$\widetilde{z}_v = \widetilde{V}_{k,A} - \widetilde{V}_{k,N} + \widetilde{\eta}_v$$

$$\widetilde{z}_v = \widetilde{I}_{d1,k,A} + \eta_v = C^T_{d1,k,A}\begin{bmatrix} \widetilde{V}_{k,A} \\ \widetilde{V}_{k,B} \\ \widetilde{V}_{k,C} \\ \widetilde{V}_{m,A} \\ \widetilde{V}_{m,B} \\ \widetilde{V}_{k,C} \end{bmatrix} + \widetilde{\eta}_v$$

Pseudo-measurements for neutrals and grounds:

$$\widetilde{z}_v = 0 + j0 = \widetilde{V}_{k,N} + \widetilde{\eta}_v$$

Non-synchronized measurements:

$$z_v = \left|\widetilde{V}_{k,A} - \widetilde{V}_{k,N}\right|^2 + 2\eta_v = (V_{k,A,r} - V_{k,N,r})^2 + (V_{k,A,i} - V_{k,N,i})^2 + 2\eta_v$$

$$z_v = P_{d1,k,A} + \eta_v = \operatorname{Re}\left\{\widetilde{V}_{k,A}\left(C^T_{d1,k,A}\begin{bmatrix} \widetilde{V}_{k,A} \\ \widetilde{V}_{k,B} \\ \widetilde{V}_{k,C} \\ \widetilde{V}_{m,A} \\ \widetilde{V}_{m,B} \\ \widetilde{V}_{k,C} \end{bmatrix}\right)^*\right\} + \eta_v$$

$$z_v = Q_{d1,k,A} + \eta_v = \operatorname{Im}\left\{\widetilde{V}_{k,A}\left(C^T_{d1,k,A}\begin{bmatrix} \widetilde{V}_{k,A} \\ \widetilde{V}_{k,B} \\ \widetilde{V}_{k,C} \\ \widetilde{V}_{m,A} \\ \widetilde{V}_{m,B} \\ \widetilde{V}_{k,C} \end{bmatrix}\right)^*\right\} + \eta_v$$

The state estimation problem is formulated as follows:

$$Min \quad J = \sum_{v \in phasor} \frac{\widetilde{\eta}_v^* \widetilde{\eta}_v}{\sigma_v^2} + \sum_{v \in non-syn} \frac{\eta_v \eta_v}{\sigma_v^2}$$

It is noted that if all measurements are synchronized the state estimation problem becomes linear and the solution is obtained directly. In the presence of the non-synchronized measurements and in terms of above formulation, the problem is quadratic, consistent with the quadratized power flow. Specifically, using the quadratic formulation, the measurements can be separated into phasor and non-synchronized measurements with the following form:

$$z_s = H_s x + \eta_s$$
$$z_n = H_n x + \{x^T Q_i x\} + \eta_n$$

In above equations, the subscript s indicates phasor measurements while the subscript n indicates non-synchronized measurements. The best state estimate is given by:

Case 1: Phasor measurements only.

$$\hat{x} = (H_s^T W H_s)^{-1} H_s^T W z_s$$

Case 2: Phasor and non-synchronized measurements.

$$\hat{x}^{\nu+1} = \hat{x}^{\nu} + \left(H^T W H\right)^{-1} H^T W \begin{bmatrix} z_s - H_s \hat{x}^{\nu} \\ z_n - H_n \hat{x}^{\nu} - \left\{\hat{x}^{\nu^T} Q_i \hat{x}^{\nu}\right\} \end{bmatrix}$$

where:

$$W = \begin{bmatrix} W_s & 0 \\ 0 & W_n \end{bmatrix}, \qquad H = \begin{bmatrix} H_s \\ H_n + H_{qn} \end{bmatrix}$$

4. Implementation

The proposed SuperCalibrator methodology is being implemented for a planned demonstration on five substations: ELDORADO and MABELVILLE substations of the Entergy system, MARCY and MASSENA of NYPA and one more of METC to be named. The demonstration is scheduled for March 2007. In this section we provide a generic description of the substation model. We have developed a computer model that can define a 3-D model of the substation with all instrumentation. The manner in which the model is developed is discussed here. A typical model of a substation (three-phase, breaker oriented, instrumentation model inclusive is illustrated in Figures 5 through 11. Figure 5 illustrates the 3-D rendered model of the substation. The 3-D model is necessary to provide information about the lengths of the instrumentation cables so that no manual entry is required for this type of data that are in general tedious. Note that the 3-D model is a detailed model with all major equipment and instrument transformers. In addition the location of the control house as well as the relay and PMU racks inside the control house are part of the model. This model is similar to models created with programs such as AutoCAD with one difference: each entry includes information that is used to develop the mathematical circuit model. For example a control cable "running" from instrument transformer A to the control house rack B is defined with each physical construction of conductor, insulation and shield. The computer program creates the electrical model from this information. The entry of the physical parameters of the cables, transformers, etc is described later with the aid of Figures 7, 8, 9, 10 and 11. Figure 6 illustrates the single line diagram. Each component in the single line diagram is a three-phase component with its specific electrical model. The way the instrumentation model is entered is shown in Figures 7 through 11. Figure 7 describes the definition of the IED (relay, PMU, etc.) and IED Identifier and some generic information (manufacturer, utility, location, etc.) about the device. For each IED the instrumentation channels and the measurements can be defined by simply clicking on the appropriate button (note there are two buttons labeled "instrumentation channels" and "measurement channels" respectively). This structure allows flexibility for proper modeling of cases where an input to an IED may be created from combination of inputs. An example is the case where the electric current in a transmission line is created as the sum of the CT output of two CTs located in the breakers of a "breaker and a half" scheme or a "double breaker" scheme. The instrumentation channels are defined with the aid of the user interface illustrated in Figure 8 and 9. Actually, the parameters of an instrumentation channel are defined in the user interface illustrated in Figure 9. Note that the inputs are intuitive. The form illustrates a visualization of the instrumentation channel with space for entering the parameters of each component of the instrumentation channel. Figure 8 provides a summary of the instrumentation channels associated with the IED. The summary form of Figure 8 is active, i.e. by clicking on any line will bring the detail model of the instrumentation channel in the form of Figure 9. Again, the method constructs the mathematical model of the instrumentation channel from the provided information. The parameters of the measurement channels are provided in Figures 10 and 11 in a similar manner. Figure 10 provides the summary of the measurement channels while Figure 11 provides the parameters/definition of a specific instrumentation channel. Note that Figure 11 illustrates a "calculator. Specifically, each measurement channels is created with operations on the already defined instrumentation channels. For example a measurement that is formed as the sum of the output of two CTs is simply defined as the sum of the two instrumentation channels that represent the two CTs. The model has been created to deal with more complex schemes. For example, in case of a filter that accepts three inputs and creates the positive sequence of the three inputs, then the measurement channel will be defined with these three inputs and the "POS" operation. Other usual operations are illustrated in the form of Figure 11. It should be clear that this form is dynamically interactive.

The end result of the above process is an integrated three-phase model including instrumentation channels and breaker location. The methodology described in the paper is applied to this model. Present work is focusing on implementing this system to operate with real time data.

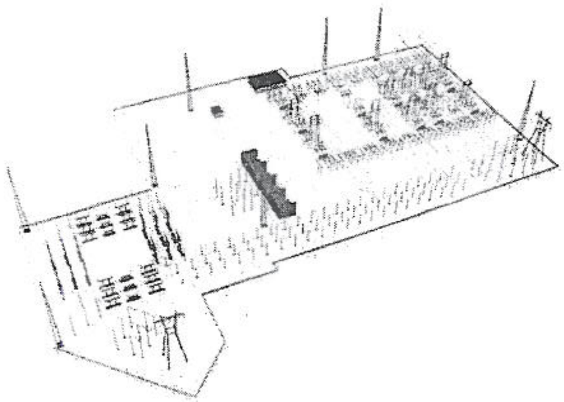

Figure 5. An Example 3-D Model of a Substation. VTs and CTs are Shown in Their Physical Position

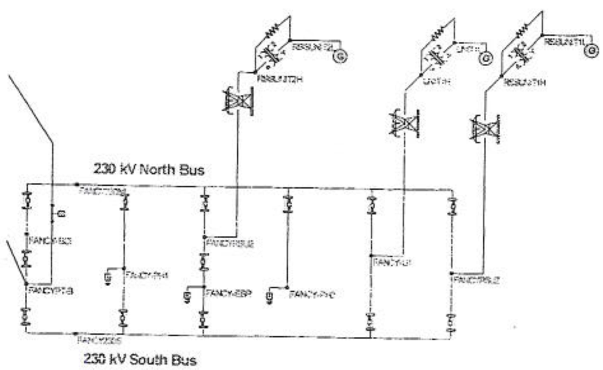

Figure 6. An Example Single Line Diagram Breaker-Oriented Model of a Substation

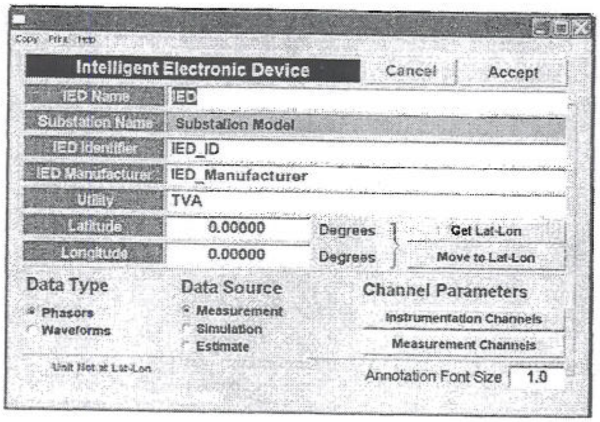

Figure 7. An Example Model of an IED (PMU, Relay, Digital SCADA) – User Interface to Define Instrumentation and Measurement Channels

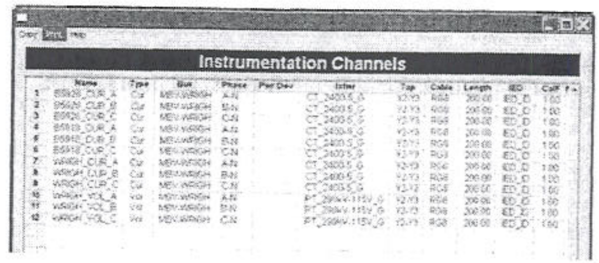

Figure 8. Instrumentation Channel Definition for the Relay of Figure 7.

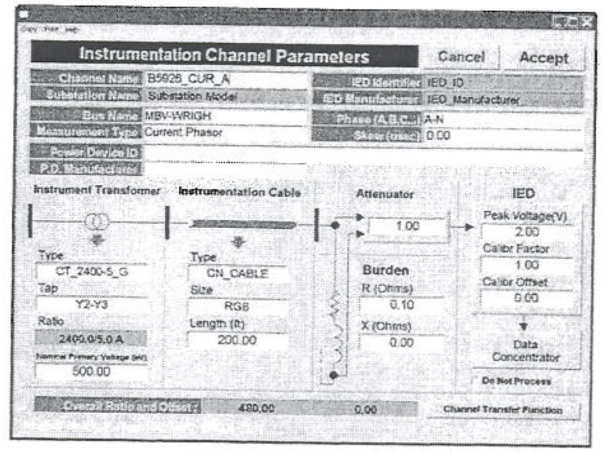

Figure 9. Physical Parameters of One Instrumentation Channel of Figure 8.

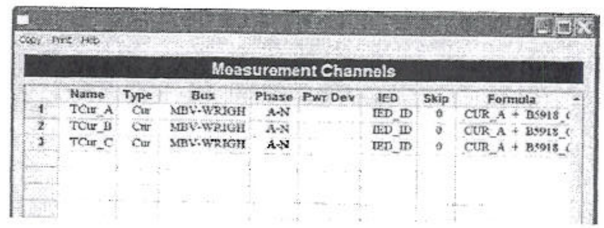

Figure 10. Measurement Channel Definition for the Relay of Figure 7.

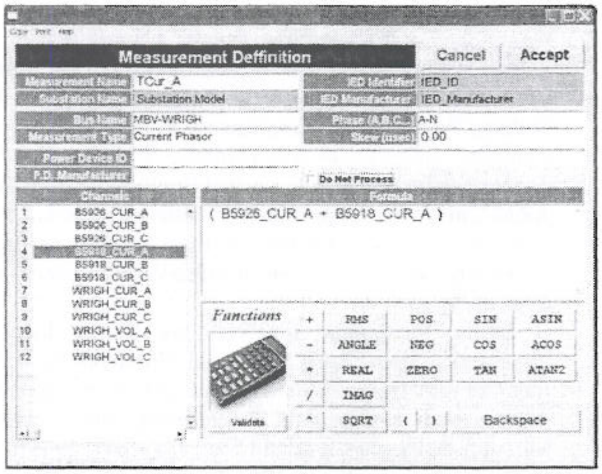

Figure 11. Physical Parameters of One Measurement of Figure 10.

5. Conclusions

This paper presented recent work and advances in the SuperCalibrator concept. The SuperCalibrator is conceptually very simple. It is simply a state estimator using a detailed three-phase breaker oriented instrumentation inclusive model. As such the errors introduced by the instrumentation are compensated and the estimated values are closer to the actual values of the electric power system. The overall methodology is a precision filter for the integrated phasor data, relay data and SCADA data at the substation level. The innovations presented here is that the methodology provides the means for correcting errors from instrumentation channels, phase shifts of different PMU manufacturers and accommodates unbalanced operation and system model asymmetries. The proposed SuperCalibrator has three additional major benefits: (a) it performs root cause analysis of events that may trigger a large number of alarms. This is a byproduct of the method since the method can identify the causing effect by identification of the system topology including stuck poles of breakers, etc., (b) it provides a desirable data compressor. The amount of available data from relays, PMUs and SCADA in a modern substation is enormous. The SuperCalibrator extracts the information included in this data. Typically this brings about an 11 to 1 reduction in the substations that have been mentioned in the paper. Now only the information can be transmitted thus minimizing communication requirements. And (c) it also provides the means for remote calibration. This is a byproduct of the state estimation residual analysis. This process has been described in an earlier paper [4].

6. Acknowledgments

The work reported in this paper has been partially supported by the NSF Grant No. 000812, the PSERC project S-22 and the CTC project "Distributed State Estimation". This support is gratefully acknowledged.

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Paul Myrda is Director of Operations and Chief Technologist overseeing planning and asset management functions for Trans-Elect's operating companies. He has been instrumental in developing an overarching strategy in asset management. Previously, Paul led the start-up of NASA's Illinois Commercialization Center. As Executive Director, he was responsible for technology transfer from NASA, DoD, SBA and EPA including an innovative grant program co-funding technology developments. Paul has over 20 years of experience including leading edge technology implementations. His diverse background includes planning, engineering, information systems and project management. He has an MBA from Kellogg and MSEE and BSEE from Illinois Institute of Technology; board member of Technology Management Association of Chicago; licensed professional engineer and a member of the IEEE and CIGRE.