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A High-Speed, Real-Time Visualization and State Estimation Platform for Monitoring and Control of Electric Distribution Systems: Implementation and Field Results

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***Abstract* — Continued deployment of renewable and distributed energy resources is fundamentally changing the way that electric distribution systems are controlled and operated; more sophisticated active system control and greater situational awareness are needed. Real-time measurements and distribution system state estimation (DSSE) techniques enable more sophisticated system control and, when combined with visualization applications, greater situational awareness. This paper presents a novel demonstration of a high-speed, real-time DSSE platform and related control and visualization functionalities, implemented using existing open-source software and distribution system monitoring hardware. Live scrolling strip charts of meter data and intuitive annotated map visualizations of the entire state (obtained via DSSE) of a real-world distribution circuit are shown. The DSSE implementation is validated to demonstrate provision of accurate voltage data. This platform allows for enhanced control and situational awareness using only a minimum quantity of distribution system measurement units and modest data and software infrastructure.**

***Index Terms* — distribution system, high penetration, monitoring, photovoltaic (PV), real-time, state estimation, visualization.**

I. Introduction

Deployments of distributed energy resources (DERs), including renewable generation such as variable and non-dispatchable photovoltaic (PV) systems on electric distribution systems continue to occur internationally at a high rate [1]. As these DERs continue to be interconnected on electric distribution systems, the method of operating the entire electric system is fundamentally changing. Historically, the distribution portion of the electric system was modeled using simple lumped loads, was largely unmonitored, and any system-level automation, control, or visualization was focused primarily at the transmission level. However, supporting sizable penetrations of DERs on distribution systems will require sophisticated active power monitoring and control to maintain stable and reliable operation within prescribed voltage and power quality limits.

Increasingly, distribution management systems (DMS), which provide basic power control and other functionalities, are being implemented. The DMS relies on local measurements provided by a supervisory control and data acquisition (SCADA) system. Reliable real-time measurements (measurements that are provided deterministically and in actual clock time) from the SCADA system are often limited because of a small total number of real-time measurement points, which may additionally have limited reliability and incomplete or inaccurate system load information [2]. This limited set of real-time measurements is not sufficient for many of the most important advanced DMS functions, such as optimization of feeder reconfiguration, capacitor switching, demand response, voltage/VAR controls, economic dispatch, system losses, and DER dispatch [3]–[7], which require a complete set of accurate system states. To obtain the complete distribution system state, DMSs use state estimation techniques.

State estimation of power systems has been developed [8] and applied at the generation and transmission levels for more than 40 years [4]. However, state estimation techniques have not been fully applied to distribution systems until more recently because of the unique challenges associated with distribution systems: very few measurements are available; there is a wide range of resistance and reactance ratio values; switch, capacitor, and regulator states are typically not monitored; there are little to no meshes; there is three-phase imbalance; and most measurements are of the current rather than voltage [4], [7], [9], [10]. Early work (e.g., [6]) recognized the possibility of applying the widely-used constrained weighted least squares (WLS) method of state estimation used on transmission systems to distribution systems for use in real-time modeling for online contingency analysis and off-line study of possible control strategies. This method, however, still depended on voltage measurements and didn't address many of the other challenges associated with distribution systems, so more efficient state estimation techniques adapted for distribution system state estimation (DSSE) based on voltage [10] and branch current [11] state variables were developed.

Since this early work, the WLS and DSSE algorithms have been further developed to allow more efficient implementation via decomposition of the WLS problem into a series of sub problems that can be parallelized [2], [4], [12] and the use of forward/backward sweep methods [4]. Additionally, studies (e.g., [13]) have examined the WLS method and compared it to other typical state estimation algorithms traditionally applied to transmission systems to statistically validate that WLS is appropriate for DSSE. With the underlying DSSE algorithms becoming more mature, more recent research efforts have focused on advancing DSSE by improving the way that measurements are implemented and used in the algorithm.

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To fully estimate the state of a power system, a minimum amount of measurement information for nodes in the power system is required. In the context of distribution circuits, historically very few field measurement points have been available for use in DSSE, and those that are available are in a mix of different electrical measurement formats that may require additional conversion before they can be used in a DSSE algorithm. Traditionally, load models based on historical billing information and samples taken at different load points (e.g., residential, commercial, industrial) across different timescales (e.g., daily load curve, seasonal) have been used as pseudo-measurements in place of field measurements for DSSE [2], [5]–[7], [10]. Because these load models provide only rough estimates of the load, the analysis is approximate at best, and therefore corresponding DSSE tools have generally been limited to planning purposes [7]. However, as advanced metering infrastructure (AMI) in distribution networks has become more prevalent, DSSE algorithms have been improved to support the more prolific, real-time, and primarily voltage-based measurements of contemporary AMI [2], [7], [14]–[16]. In addition, algorithms that optimize the quantity and locations of distribution electrical metering infrastructure to simultaneously improve DSSE accuracy and allow the minimum meter cost/benefit ratio [17]–[21] have been developed.

Despite all of this DSSE research and development and the promise of the many powerful real-time DMS control capabilities that depend on it, there have been very few practical field implementations and demonstrations of the technique. Lubkeman et al. presented an early implementation that utilized load models as pseudo-measurements with non-real-time, low-speed (data recorded every 15 min and retrieved weekly) measurements from a New York distribution feeder that showed the promise of DSSE techniques but experienced challenges, especially related to the use of load data that was constructed using multiple sources of load data and customer billing information [3]. Deng et al. developed and applied a DSSE algorithm to a distribution feeder located in China with 10 live measurement points, but limited estimation data and implementation details (e.g., measurement speed) are disclosed [4]. Simendic et al. performed an in-field verification of DSSE techniques on a Serbian distribution system and showed the effects of using varying ratios of historical data and live measurements as DSSE model inputs, but neglected to provide any details about the type, number, or collection frequency of live measurement points [22]. Katic et al. presented the results from testing DSSE applied to a Guizhou, China distribution circuit with field measurements collected each hour from the 10-kV secondaries of substation transformers and the 400-V secondaries of feeder distribution transformers (number of measurement points not disclosed) [14]. Of these few practical field implementations of DSSE, all demonstrated the capability in a non-real-time (offline) capacity or at a timescale (e.g., 1 h) that is not relevant to the faster (i.e., 1 s to 1 min) real-time control applications needed for the integration of highly-variable, non-dispatchable renewable DERs.

In this paper, an implementation and field demonstration of a high-speed (an approximate 1-Hz update rate with 10 s to 30 s of latency) DSSE platform capable of real-time simulations at the 30-s timescale is presented. The platform makes use of existing state-of-the-art DSSE capabilities available as part of the open-source OpenDSS [23] software package and a network of live, high-speed measurements from custom-developed (though similar units are now commercially available) distribution system monitoring units (DMUs) deployed on a California distribution system. The high-speed, real-time DSSE functionality is then demonstrated using a custom-developed web-based power system visualization application with scrolling strip charts and an annotated distribution system map. This paper presents a novel demonstration of how high-speed, real-time DSSE and related control and visualization functionalities can be achieved using existing open-source software and commercial monitoring hardware.

II. High-Speed, Real-time Visualization and State Estimation Platform Overview

Since 2009, the National Renewable Energy Laboratory (NREL) and the U.S. Department of Energy (DOE) Solar Energy Technologies Office have been developing and implementing a platform for the purposes of providing real-time monitoring and visualization and data collection for a number of projects focusing on the deployment of high penetrations of solar photovoltaic installations in electric distribution systems. Initially, this platform consisted of deployments of custom-developed DMUs capable of providing time-synchronized collection of high-speed (up to 10 Hz) phasor voltage, current, frequency, complex power, and transformer enclosure temperature measurements from distribution transformers (electrical measurements are taken at the secondary). These measurements are sent in real time through a cellular network to data concentration, historization, and visualization infrastructure at NREL [24], [25]. Data concentration and historization functions are implemented using the OpenPDC [26] software package.

This initial platform has been very effective for high-penetration PV research efforts, with more than three years of high-speed data collected from more than 30 units deployed in three U.S. electric utility service territories. The platform was implemented using custom-developed DMUs, because at the time no commercial product existed that could meet the requirements to provide high-speed, phasor-based, time-synchronized data reliably from the hot, often wet environment of a distribution transformer. However, the platform is compatible with any device that can communicate using the IEEE C37.118 Standard for Synchrophasors for Power Systems [27], including recently developed commercial products with similar capabilities as the NREL DMU.

The focus of more recent efforts (and this paper) has been on the expansion of this platform to include (1) a 2-D scrolling strip chart and annotated map-based real-time visualization from a web application and (2) real-time state estimation capabilities. The complete, implemented platform is shown in the architecture diagram of Fig. 1. DMUs deployed in the field sample sensors at 256 samples/line cycle; perform phasor, root mean square (RMS), and power calculations; format the final RMS phasor quantities into the frame format specified by IEEE C37.118; and then send this data using a cellular network (typical) to data concentration servers at NREL at a user-configured data rate (typically 1 Hz). The data streams from individual DMUs are then concentrated and forwarded on to the data historization and application server. This server organizes and archives the data while also running the local DSSE process. When enabled, the DSSE process is triggered with each new receipt of data (usually every second, but it depends on the user-selected data rate). Upon conclusion of the DSSE process, which is described in detail in Section IV, the resulting circuit state estimation data is packaged and then forwarded via Secure File Transfer Protocol to the data visualization web server. The visualization server uses this data to generate dynamic visualizations for end users through a web interface (detailed in Section III) upon request.

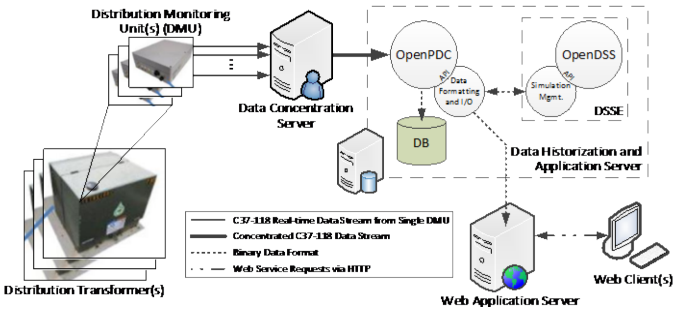

Fig. 1 NREL data collection, state estimation, and visualization platform

The entire process from measurement to displayed data visualization at the web application takes 10 s to 30 s. For this implementation, data at the visualization application is updated every second. Thus, the end user sees data updates every second, but the data is typically 10 s to 30 s old. For real-time modeling applications, in which deterministic data must be input to or combined with a model in actual clock time, this system would be limited to simulations with an approximate 30-s time step.

III. Web-Based Visualization Interface

The visualization interface plays a key role in the overall platform because it allows users to view, using intuitive 2-D visualizations, the measured and estimated state of that entire distribution network. Power system analysis and visualization tools—including PowerWorld [28] and GreenGrid [29], custom network monitoring tools (e.g., [30]), and live measurements provided via SCADA systems—are commonplace for utilities and the power system community. However, these tools are generally focused on the visualization of historical or projected data at the generation and transmission levels, and many provide only simple numeric or trend displays of this data instead of system-level visualizations. In more recent years, deployments of phasor measurement units across power systems—including in projects such as FNET [31], NASPI [32], and WAMS [33]—have enabled higher speed measurement and encouraged the development of a number of visualization applications, such as the FNET web site [31], which shows frequency and phase angle deviation contours on a U.S. and world map, and a related desktop application [34] capable of showing voltage magnitude, phase angle, and frequency contour plots in addition to individual phasor trend graphs.

Tools for visualizing data closer to the distribution level do exist; however, such tools generally focus on monitoring a single home [35], building, or other asset or on only visualizing limited information, such as fault locations or switching operations [36]. Historically, when distribution systems had only unidirectional power flow and little-to-no installation of DERs, this was appropriate, but with accelerating deployments of DER installations on distribution networks occurring, new tools are needed at the distribution system level.

The visualization interface developed for this project is purpose built for visualizing the entire state of a distribution system using live data. The visualization interface is implemented using a web application, developed using open-source web technologies including HTML and the Processing.js JavaScript library [37], to provide easy access to authenticated users by requiring only a common web browser as the local software. To access visualizations, an authenticated user opens the visualization web application in their web browser and then the client-side programming logic connects to the live data stream and circuit configuration information, provided by the server-side logic, and displays two sets of graphics to the user: scrolling strip charts of key measurements and an annotated, GIS-based, circuit map showing the overview of voltage and power flow conditions in the system. These visualizations provide critical, at-a-glance understanding of how a distribution system is operating in real time.

A. Strip Charts

A view of the application's strip chart display is shown in Fig. 2. In the current implementation, one such chart plots system voltages and another plots real and reactive powers, though any of the other measured quantities could also be plotted. Drop-down menus at the left of each chart allow the user to select which physical DMUs (in theory, state estimated data could also be displayed, but it wasn't for this implementation) to display. The numerical display to the right of the drop-down menu shows the latest floating-point voltage or power value from the selected DMU or indicates if data is unavailable. The strip chart of live voltage values from up to six different meters is shown at right. Individual data points are plotted as available (up to one per second). The strip chart shows approximately 25 s worth of data and scrolls in real time to always show the latest data at the right side of the chart.

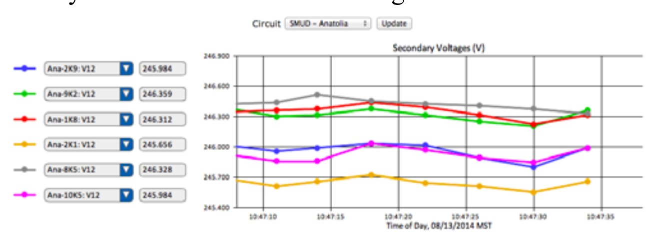

Fig. 2 Strip charts are used to view real-time power system data from any measurement point (selected using the drop-down menus at left). The strip charts scroll in real time and show approximately 25 s of data.

B. Annotated, GIS-Based, Circuit Map

An example of the annotated, GIS-based, circuit map is shown in Fig. 3. The circuit map is drawn using utility GIS data and then individual phases and DMU (transformer) locations are labeled appropriately. Each metering point is represented by a colored circle, which indicates the status of live data from that meter and the voltage at that point. Meters not reporting live data have a red outline filled with black. Meters reporting data have a black outline filled with a color corresponding to the voltage scale shown. Numerical values of voltage, real power, and reactive power are displayed in a table that is shown when the user's mouse hovers over a metering point (see Fig. 4). The entire map can be magnified and panned. All points on the circuit are colored according to the voltage scale shown based on the output of the real-time state estimation component (described in Section IV). The line width of each branch segment represents the relative real power flow (e.g., see Fig. 3) on that branch of the circuit. Voltage and power flow information for any point on the circuit (via state estimation) can be obtained by hovering over a line segment.

Fig. 3 GIS-based circuit map overview shows voltage (color) and power flow (line width) information for all points on the distribution system, in addition to detailed information at metering points (colored circles)

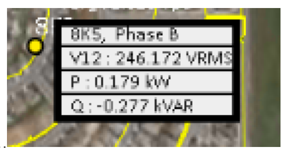

Fig. 4 Live voltage, real power, and reactive power information is shown when the user hovers over a metering point (yellow circle at upper left).

IV. Real-Time State Estimation Module

The state estimation module is implemented using the circuit modeling, load allocation, and power flow features of the OpenDSS [23] platform with additional custom scripting to provide the additional connection to live data, perform pre-estimation, and format and transmit data to the visualization interface. DSSE is accomplished in the same four-step process common to many DSSE implementations (e.g., [14]): (1) pre-estimation, (2) measurements and topology verification, (3) load allocation (or calibration), and (4) power flow calculation.

A. Implementation

1) Pre-Estimation

The first step in the DSSE process is to obtain a power flow calculation for the baseline, planning circuit model at the considered point in time. Depending on the circuit model in use and the detail of planning loads in that model, this may be as simple as a static calculation (in which case it is only computed once) or as complex as second-by-second calculations. This is accomplished using OpenDSS for this example.

2) Measurements and Topology Verification

The second step is to verify the live measurements and, if applicable, the circuit topological information (e.g., status of operable switches). In this implementation, measurements are verified at the data concentrator (see Fig. 1), which determines data quality based on successful receipt of the data and whether that data is within allowable tolerances. Once data quality of individual measurements has been determined, an assessment of whether sufficient data needed to continue with DSSE exists is made. In this implementation, if two or more measurements are available, the DSSE process continues to the next step, which will ultimately determine if sufficient data is available. More sophisticated algorithms for measurement verification, such as the constrained optimization procedure presented in [14], are available; however, this simple process was found to be sufficient for this implementation. Many DSSE implementations (e.g., [14]) also perform circuit topological verification at this stage; however, this function has not been implemented in this example because it was not necessary for the distribution feeder circuit models used thus far.

3) Load Allocation and 4) Power Flow Calculation

Load allocation is performed using the *Estimate* functionality of OpenDSS. A prerequisite for this function is that the estimated peak current (all three phases) at the feeder head and any known line current values (from DMU live data feeds) are first defined. For this implementation, the estimated feeder head current is determined by:

$$I_{fh,est,i} = I_{fh,pe,i} \cdot \frac{\sum_n I_{b,rt,i,k}}{\sum_n I_{b,pe,i,k}} \qquad (1)$$

where $I_{fh,est,i}$ is the estimated and $I_{fh,pe,i}$ the pre-estimated (from step #1) feeder head current on phase i and $I_{b,rt,i,k}$ is the latest and $I_{b,pe,i,k}$ the pre-estimated branch current value for branch $k = 1 \dots n$ on phase i. With the feeder head and branch current information specified, the *Estimate* function then iteratively determines (via power flow solution) the system state that minimizes the errors between the estimated and actual branch current values. When complete, these errors are examined to ensure they are within a user-specified tolerance; if all values are within the specified tolerance, the system state is passed along to the visualization interface.

B. Validation

The DSSE module was validated using a set of eight DMUs implemented in the real-world system described in Section V. Measurements from four DMUs were used as the data input to the DSSE modules and then the voltage state outputs from the DSSE module were compared to the voltage measurements from the remaining four DMUs. This comparison was made using historical 1-s data, sampled once per hour, from three 24-h periods from spring, summer, and autumn of 2013. Fig. 5 shows a plot of this comparison for one DMU for July 11, and Table 1 shows the daily average percent error in measurement for all four of the DMUs used in this example.

Table 1. Results of DSSE Validation of Voltage Measurements

Date	**Average (over 24 h) Percent Error in Voltage Measurement Compared to Voltage Estimation at**			
	DMU1	**DMU2**	**DMU3**	**DMU4**
5-May-13	0.64	0.59	0.50	0.56
11-July-13	0.78	0.74	0.64	0.63
23-Oct-13	1.22	1.20	0.61	0.59

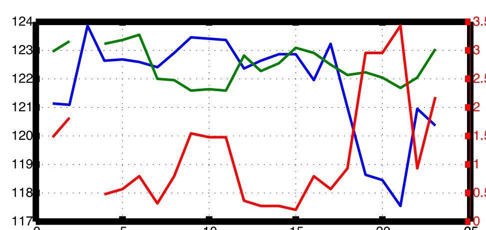

Fig. 5 Results of DSSE validation of DMU1 voltage measurement for 24 hourly samples on July 11, 2013

V. Field Implementation

The field implementation used to demonstrate the real-time state estimation and visualization platform includes a set of 12 DMUs that have been installed on a distribution feeder near Sacramento, California, USA served by the Sacramento Municipal Utility District (SMUD). The feeder is powered from a 115:13.8-kV transformer at the substation (upper left of Fig. 3) and, among other areas, powers a subdivision (lower right of Fig. 3) of homes, most of which have PV systems installed in addition to other DER technologies such as residential energy storage systems and plug-in electric vehicles.

The 12 DMUs are installed at the secondaries of 13.8:0.12/0.24-kV distribution transformers, each of which serve approximately 10 homes. The DMUs were strategically placed to obtain a set of measurements along the length of feeder at each phase. Each DMU is time synchronized using GPS and configured to provide voltage, current, and complex power RMS phasor measurements as well as frequency, power factor, and transformer enclosure temperature every second to the data collection network at NREL. SMUD provided NREL with a detailed SynerGEE model of the network, which NREL converted to OpenDSS format for use with the state estimation module. The example visualizations shown in Section III and the state estimation results shown in Section IV were from this field installation.

VI. Conclusions and Future Work

This paper presented a novel demonstration of a high-speed, real-time DSSE platform and related control and visualization functionalities implemented using existing open-source software and custom (though similar commercial versions are now available) DMU hardware. Live scrolling strip charts of meter data and intuitive annotated map visualizations of the entire state (obtained via DSSE) of a California distribution circuit were shown. The DSSE implementation was validated to provide accurate (within 3.5%) voltage data at four selected DMU locations over three 24-h periods selected from different seasons. The platform, as currently implemented, provides updated data and visualizations at 1 Hz and with a delay of 10 s to 30 s, making it useful for real-time simulations at the 30-s timescale.

The immediate application of this platform is enhanced situational awareness, via intuitive, comparatively high-speed (1-Hz) live visualizations of an entire distribution system (instead of only the limited metering points) using only a minimum quantity of distribution system measurement units and modest data and software infrastructure. However, this platform also enables additional system control and DMS functions that will allow for enhanced real-time operation and simulation of a changing electric distribution system.

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