Received 1 April 2021; revised 16 July 2021; accepted 30 July 2021.
Date of publication 9 August 2021; date of current version 9 November 2021.

Digital Object Identifier 10.1109/OAJPE.2021.3103496

A Multi-Site Networked Hardware-in-the-Loop Platform for Evaluation of Interoperability and Distributed Intelligence at Grid-Edge

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This work was supported in part by the U.S. Department of Energy under Contract DE-AC05-76RL01830.

ABSTRACT Electric power systems have experienced large increases in the number of intelligent, connected and controllable devices being deployed, leading to a high degree of distributed intelligence at the grid-edge. These devices, both utility-owned and consumer-owned, include renewable generation, energy storage, remote switches, voltage regulators, and smart controllable loads. These new devices provide significant potential for increased operational flexibility that can be leveraged to achieve system reconfiguration, resiliency improvements, power quality improvements, and distribution system automation. However, two significant challenges must be addressed before these assets can be leveraged for operations: interoperability and system level validation prior to deployment. Because of the complexity of distributed control systems, and their interactions with legacy centralized controls, a purely simulations-based approach for pre-deployment validation is not sufficient. It requires hardware-in-the-loop (HIL) testing to emulate hardware devices and evaluate their performance. Additionally, securely integrating multiple test facilities at utility operators and vendors can enable the rapid scale-up of evaluation platforms and remove the need for multiple expensive standalone installations. Presented in this paper, is the development of a multi-site evaluation platform that employs Advanced Distribution Management Systems (ADMS), distributed control devices, real-time HIL assets, secure communication links, and protocol adapters. The testbed has been developed at three sites, with one site hosting the ADMS and the other two hosting HIL capabilities. This platform uses standards-based approaches and open-source tools, and hence can serve as a template for other researchers and institutions to implement their multi-site evaluation frameworks for pre-deployment testing.

INDEX TERMS Distributed control, distributed energy resources, hardware-in-the-loop, microgrids, power system resiliency.

NOMENCLATURE

d, q	direct and quadrature axes
i_d, i_q	direct and quadrature axes currents
v_d, v_q	direct and quadrature axes voltages
v_{grid}, f_{grid}	grid voltage and frequency
v_{nom}, f_{nom}	nominal grid voltage and frequency
i_a, i_b, i_c	a, b, and c phase currents
v_a, v_b, v_c	a, b, and c phase voltages
m_a, m_b, m_c	a, b, and c phase modulation indices
P_{ref}, Q_{ref}	real and reactive powers
L	filter inductance
C	filter capacitance
ω	angular frequency
t	time
Superscript *	reference value

I. INTRODUCTION

A SAFE, reliable, resilient, and clean electric power infrastructure is an essential element of modern society. Failures in the electrical power infrastructure can result in lost economic productivity and increased risk of loss of lives due to service outages [1]. Power outages on a regional scale can occur as a result of natural events such as extreme storms and earthquakes [2], [3] or, as part of complicated cascading failures such as the 2003 North American blackout [4]. More recently in early 2021, acute and severe winter storms led to cascading failures in the Electric Reliability Council of Texas interconnection in the United States, underscoring the continuing vulnerability of power grids to natural events [5]. Significant generation losses due to faults induced by events such as wildfires (e.g. Canyon 2 fire, Blue Cut fire) also lead to system instabilities and outages [6], [7]. It is therefore imperative not only to improve the reliability of the power grid to prevent system failures, but also to achieve a high level of resiliency to restore normal operations after outages. Due to the increasing deployment of distributed energy resources (DER) and intelligent electronic devices (IED), there is increasing interest in using DERs as "grid-edge" management devices to support operational flexibility across a range of operational conditions [8].

A. INCREASING DER PENETRATION LEVELS AND DISTRIBUTION SYSTEM MANAGEMENT CHALLENGES

Around the world, renewable portfolio standards, public interest, and decreasing equipment costs are resulting in increased penetrations of DERs. This includes both utility and non-utility DERs such as solar photovoltaics (PV) and battery energy storage systems (BESS), at the distribution level [9]–[11]. In the United States for example, several states have experienced sustained growth in DER installations and continue to do so [12]–[15]. DERs in many cases are connected to the lower voltage single-phase terminals of distribution transformers [16]. This simple design enables DER adoption at greater levels by residential and small commercial consumers. However, as the penetration levels of non-utility DERs increase, using the same simple, uncoordinated structure can negatively affect the operation of centrally coordinated systems such as self-healing [17]. With many jurisdictions elevating their targets for distributed and sustainable generation capacities to 100% during the next two decades, power system management challenges arising from increasing DER penetration levels could likely become more acute and widespread [18], [19].

Moving towards a distributed control and communication architecture represents a paradigm shift in multiple areas (automation, optimization, communication) for modern utilities. As the complexity of the system increases, utilities are becoming increasingly dependent on advanced control systems such as Advanced Distribution Management Systems (ADMS). Understanding how DERs might be engaged in coordination with centralized systems such as ADMS is essential prior to deployment. Also, system operators will be slow to accept and adopt new technologies unless they have been fully tested and validated.

B. DISTRIBUTED INTELLIGENCE AND INTEROPERABILITY AT THE GRID-EDGE TO INCREASE OPERATIONAL FLEXIBILITY

Distributed intelligence and controls enable the flexibility needed to facilitate safe, reliable, and secure integration of inverter based DERs, independent of the asset ownership structure. A hierarchical control structure for microgrids with primary, secondary, and tertiary control functions has been standardized and studied [8], [20]–[23]. Primary (fast, local device) control provides inverter-level current and voltage references, and also regulates power sharing through techniques such as droop control. Secondary (slower, intermediate level) control provides controls such as power quality improvement, and regulation of real and reactive power flow in the system. Tertiary (slowest, global level) control manages the coordination of resources, interconnection, and cost optimization, and this layer includes applications such as self-healing. As more and more utilities invest in tertiary control systems, such as ADMS or distributed energy resource management systems (DERMS) to manage and dispatch set points to primary control grid assets (e.g. protection & control devices, inverters), it will become more challenging to coordinate bidirectional power flows from intermittent generation, or to remediate unplanned outage events. This is especially true without an automated secondary control system to quickly federate and communicate actionable data between the back-office systems and end devices. However, direct interfaces between tertiary systems come with major challenges such as system latency, topology fidelity, and protection coordination. Additionally, most traditional grid management decisions are centralized. As a result, it can be challenging to deliver multiple concurrent use-case scenarios such as solar smoothing, volt-var management, self-healing, and microgrid islanding. But this can be achieved by distributing the grid constraints and optimization logic to a secondary control system associated with the specific circuit segment.

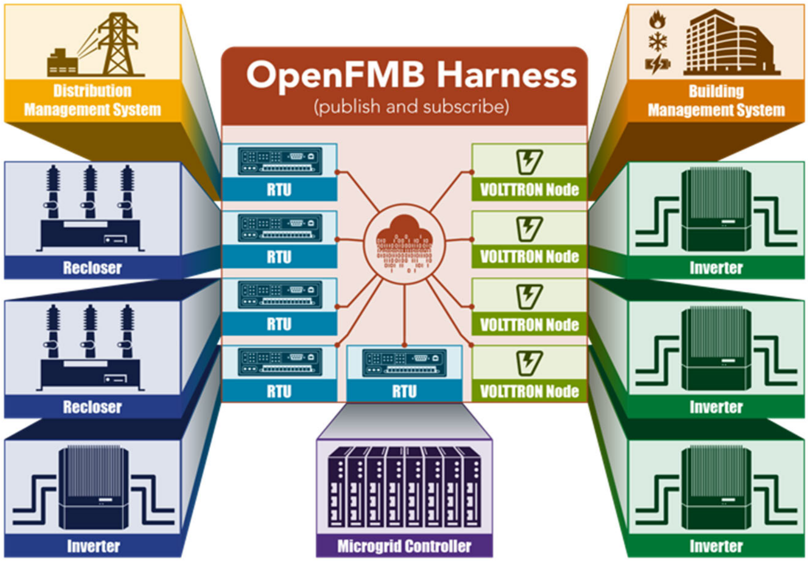

FIGURE 1. **Conceptual view of OpenFMB publish-and-subscribe harness deployed at the grid-edge, running on RTUs integrated into utility-owned assets, and VOLTTRON nodes integrated into non-utility owned assets.**

C. EVALUATING INTEROPERABILITY AT-SCALE PRIOR TO FIELD DEPLOYMENT

In a distributed control system, DERs and other field devices can communicate peer-to-peer at the application layer. The advantage of this architecture is that it avoids having to send all signals through a centralized control center. Such capabilities which are additional to existing power system functions, need to be tested and validated prior to field deployment. This presents an interoperability and scalability problem, where quickly and cost-effectively evaluating large numbers of hardware devices spread over a potentially large geographical area is required. Legacy testing methods might have relied heavily on co-located hardware devices using analog and digital I/O (inputs/outputs), but the advent of real-time hardware-in-the-loop (HIL) simulation tools can accelerate testing efforts substantially, reducing barriers to deployment [24], [25]. Additionally, the expansion of communication capabilities enables the networking of several sites (utilities, vendors, testing laboratories) so the emulation of power system components can now be spread out, achieving cost-effective scalability while not sacrificing the speed and fidelity of results. This can lower costs and set-up times significantly for the evaluation of complex control systems and algorithms.

Traditionally, utilities are accustomed to centralized Supervisory Control and Data Acquisition (SCADA) systems for unidirectional power flow. This centralized approach has challenges when operating a grid with bidirectional power flow. Because of the challenges associated with centralized approaches, utilities need to consider de-centralized approaches. The multi-site experimental testbed presented in this research work leverages simulation and emulation capabilities to help users better understand (1) the impacts and benefits of distributed controls and grid-edge interoperability, (2) coordination with legacy central systems, (3) prediction of issues arising from both power and communication perspectives (for example, communication latencies). HIL evaluation efforts presented here leverages investments made by government agencies, research and national laboratories, universities, and industries, to enable a more thorough evaluation of system impacts. Concepts can be iterated upon and refined before deployment in operational systems.

This paper presents an operational use-case in the south-eastern United States where the coordination of centralized self-healing systems and distributed solar PV has resulted in operational challenges. The utility is seeking to deploy a distributed control system to coordinate centralized and distributed assets, as part of a project sponsored by the US Department of Energy [26]. This paper discusses in detail, the establishment of secure and networked HIL testing capabilities at multiple sites. The rest of the paper is structured as follows: In Section II the conceptual development and advantages of interoperability publish-and-subscribe (pub/sub) harnesses are discussed; Section III presents the component elements of a multi-site networked HIL testing platform for distribution systems; Section IV discusses experimental results performed using the platform; and Section V presents conclusions.

II. DISTRIBUTED INTELLIGENCE AND CONTROL EMPLOYING INTEROPERABILITY PUB/SUB HARNESS

As discussed in the Introduction section, the importance of distributed intelligence for power utilities is increasing. Distributed intelligence has also been a focal point for

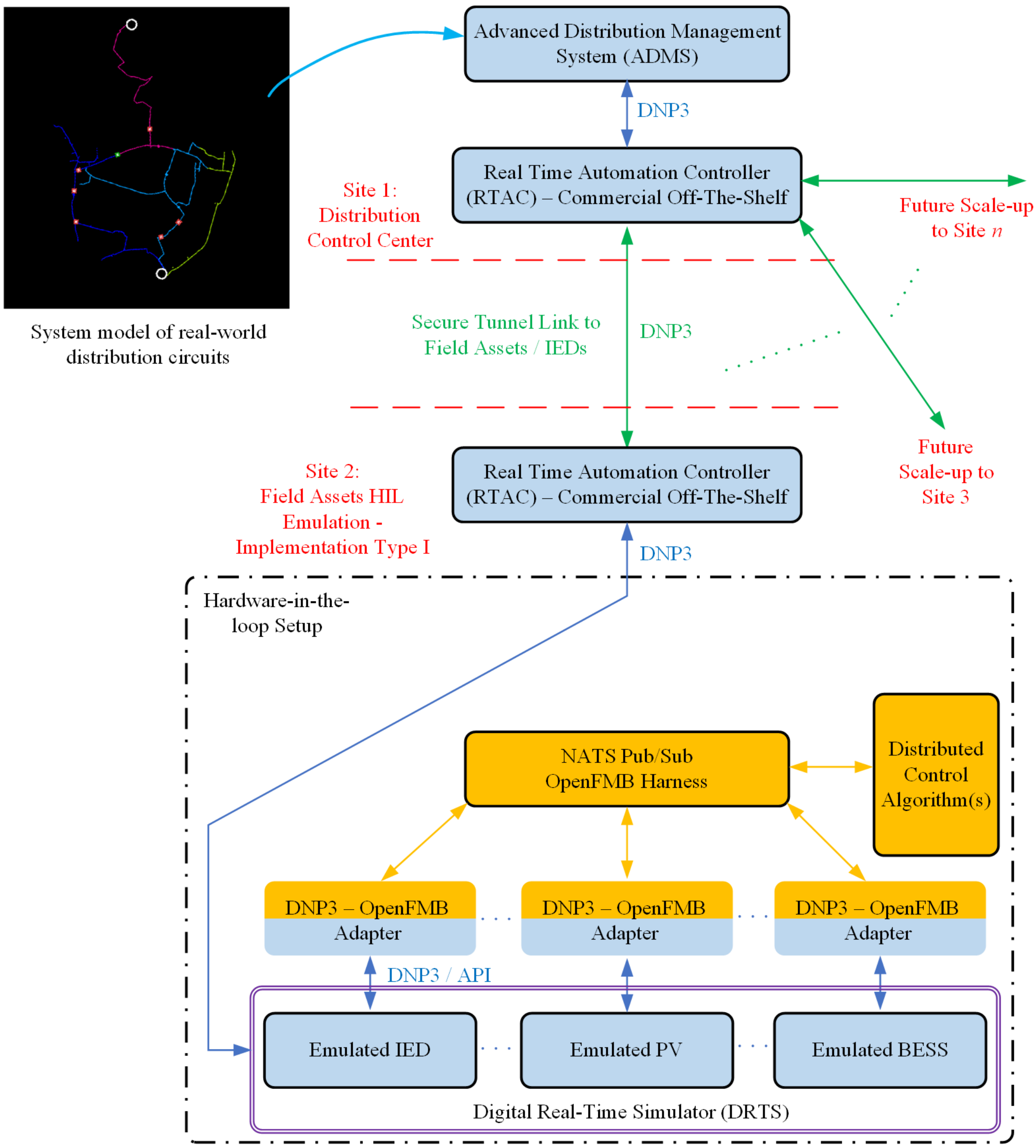

FIGURE 2. Multi-site laboratory testbed for the evaluation of OpenFMB based distributed control at the grid-edge, with field assets implementation Type I.

recently published standards such as the IEEE Standard 1547-2018 "Interconnection and Interoperability of Distributed Energy Resources" [27]. This standard prescribes communication protocols such as Smart Energy Profile 2 (SEP2) [28], Distributed Network Protocol 3 (DNP3) [29], and SunSpec Modbus [30]. Standardization of protocols for DER communications is a significant step forward and likely to improve grid functions [31], but this currently does not support peer-to-peer communications with other IEDs or offer retrofit opportunities for pre-existing assets.

Operational coordination of a subset of DERs with a centralized self-healing system requires communications with the central location, typically the distribution operations center [32]. Such interfaces with centralized systems present problems in scalability, failure modes, and communication latencies [33]. Various forms of distributed controls have been proposed and examined in the literature [26], [34]–[38]. While the proposed distributed controls provide the potential for increased resiliency, there remain challenges, such as: (1) commercial off-the-shelf (COTS) devices typically only support point-to-point SCADA protocols; (2) cybersecurity issues associated with interfacing utility-operated industrial control systems and non-utility devices [39].

Remote hardware-in-the-loop (rHIL) capabilities have been demonstrated to show networked testing, employing co-simulation capabilities, microgrid control, and distribution system control; and significant improvements to microgrid controller evaluation capabilities have been shown [17], [40]–[43]. These demonstrations resolve some of the scalability questions, but interoperability of new and

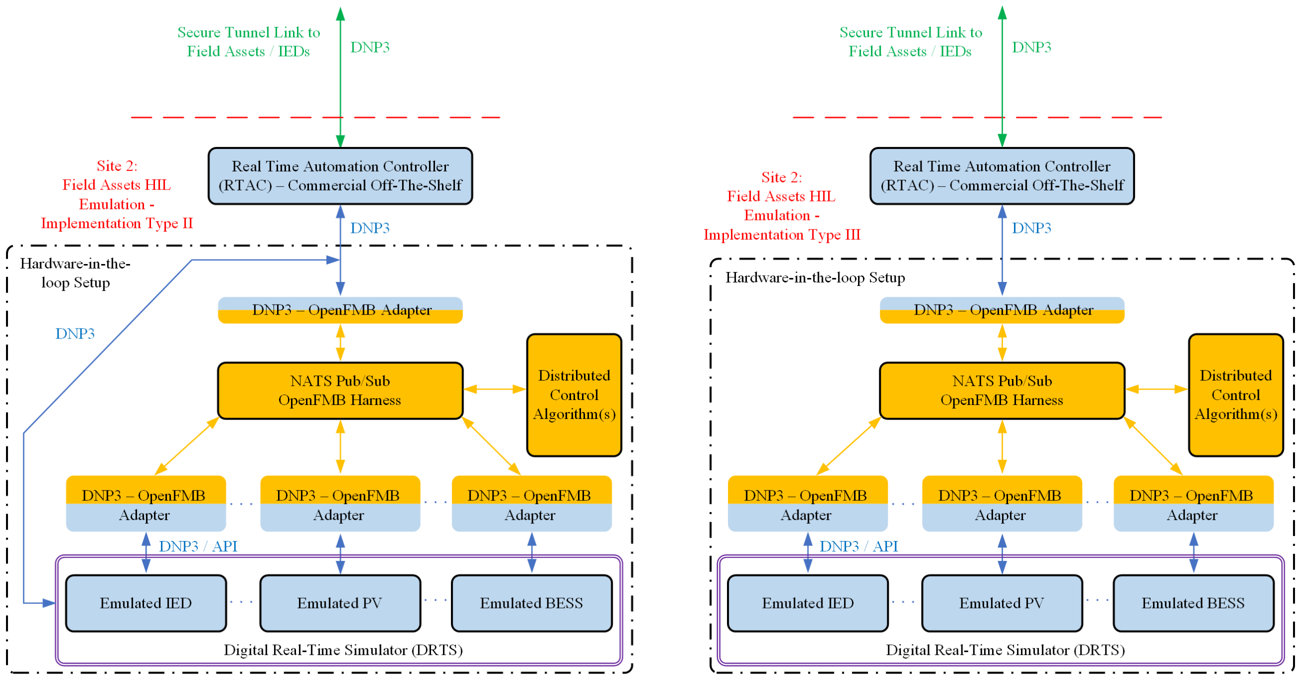

FIGURE 3. Multi-site laboratory testbed field assets implementation Type II and Type III for evaluation of OpenFMB based distributed control at the grid-edge.

existing assets remains an open issue. All these factors necessitate a more comprehensive solution.

An architecture for distributed power system controls that increases the operational flexibility of centralized and distributed systems was presented in [26]. The architecture, shown in Fig. 1, for a distributed control system uses COTS equipment and a distributed control architecture. The architecture is developed using the Open Field Message Bus (OpenFMB™) framework [39]. This is a publish-and-subscribe (pub/sub) framework and reference architecture that enables the coordination of grid edge devices through interoperability and distributed controls [39]. The harness reduces dependence on centralized control and runs on COTS devices such as Remote Terminal Units (RTU) for utility owned devices and VOLTTRON nodes for non-utility devices [44]. OpenFMB adapters act as translators, enabling communication between such varied protocols as: DNP3, Modbus, American National Standards Institute (ANSI) C12, Message Queuing Telemetry Transport (MQTT), Data Distributed Service (DDS), Generic Object Oriented Substation Event (GOOSE) messages, Advanced Message Queuing Protocol (AMPQ), and IEC 61850. OpenFMB adapters have been developed, tested, and placed in the open source [39].

OpenFMB implementations of the secure pub/sub harness provides several significant advantages:

1. Leveraging a consistent data model, based on Common Information Model (CIM)/61850 industry artifacts, as well as modern open source pub/sub protocol standards that enable secure, transport-agnostic, and peer-to-peer message exchanges between devices, systems, and applications.
2. Providing ubiquitous situational awareness.
3. Achieving sub-second system latencies for secondary control applications between disparate grid-edge devices, such as protection and control, and DER inverters.
4. One of the foundational use-cases, called DER Circuit Segment Management, defines coordination services that can be distributed locally at the grid-edge device to enhance asset precision, improve operational resiliency, and eliminate the reliance on high-availability wide-area communications.
5. Support for multi-vendor interoperability that allows a simple retrofit process to existing grid equipment, while also enabling new applications to run in coordination with them.
6. Enabling new edge-asset capabilities such as remote firmware updates, and device configuration updates.
7. Providing a zero-trust security architecture, requiring a chain-of-trust and mutual authentication among all devices and applications on the network where white-listed messages can be exchanged.

Although the deployment of a distributed control harness provides a number of potential benefits, it must be validated prior to deployment. The deployment of the harness-based multi-site evaluation platform could take three possible formats: Types I, II, and III as shown in Fig. 2 and Fig. 3. Type I provides an OpenFMB pub/sub harness independent of the existing DNP3 link with the ADMS. This approach allows for the installation of distributed intelligence and control at the grid-edge without disrupting the existing links with the distribution control center. Type II links the ADMS DNP3 communication to the OpenFMB pub/sub harness through an adapter. This enables a direct link between the ADMS

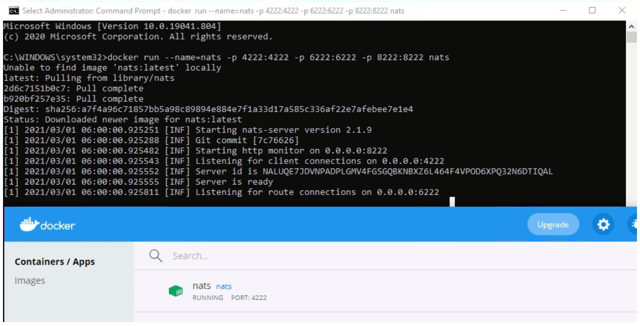

FIGURE 4. Docker container (NATS) created in order to integrate with TyphoonHIL DRTS model.

and the harness, but DNP3 is available as a fallback option for legacy system operations. Type III introduces adapters into the singular communication pathway, hence comprehensive vendor development and support become essential. Types I and II preserve traditional communication protocols, and might enable more retrofit opportunities and faster field deployments.

III. CONSTRUCTION OF MULTI-SITE EXPERIMENTAL TESTBED AND CASE STUDY SETUP

In this work, a three-site networked evaluation platform is set up using the Type I implementation described in Section II and shown in Fig. 2. The three sites are located at National Renewable Energy Laboratory (NREL, Golden, Colorado), University of North Carolina at Charlotte (UNCC, Charlotte, North Carolina), and Oak Ridge National Laboratory (ORNL, Oak Ridge, Tennessee); with the former serving as the distribution control center (site 1), and the latter two housing the HIL (from TyphoonHIL) emulated and hardware emulated field assets respectively (site 2).

A. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

ADMS are complex software systems that require consistent maintenance and updates after initial commissioning. Installing, operating, and maintaining an ADMS for an HIL experimental platform requires significant time and resources. In this experimental setup, an ADMS with Fault Location, Isolation, and System Restoration (FLISR) located at NREL is securely connected to the HIL setups at UNCC and ORNL so that duplicate ADMS deployments are not required.

The ADMS used in this research work is a commercially available system developed by General Electric [45]. The distribution circuits modeled in this system are of a real-world system located in southeastern United States. This ADMS contains multiple applications to manage the distribution system models. For the research project described here, FLISR is used. The FLISR applications in the ADMS use field assets during faults to restore power to the distribution system. An in-depth analysis of the FLISR application for a distribution system can be found in [46]. The ADMS senses the state of the system and controls field assets through the SCADA system. The SCADA system in the experimental setup presented here uses DNP3 to communicate with the field assets. Because there are limited Internet Protocol (IP) addresses available when using research facilities, a data manager was used as a data concentrator and communicates with the external facilities through the secure link created between the different facilities. Data managers also exist at the remote facilities to act as data concentrators. Data managers might or might not exist in a field deployment, but they are necessary for stable remote HIL experiments between remote locations.

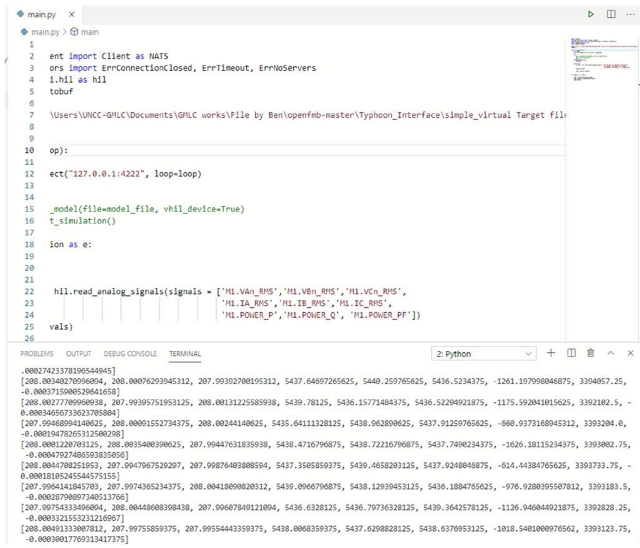

FIGURE 5. Measured electrical quantities such as voltages and currents from TyphoonHIL model simulation are published on to the secure Docker container, as seen in the Visual Studio Code environment.

B. DISTRIBUTED INTELLIGENCE SECURE LINK SETUP

The secure link between the sites utilizes the infrastructure enabled by the Energy Sciences Network (ESnet), a high-performance optic fiber network created and managed by the US Department of Energy [47], capable of speeds up to 100 Gbps. The fully functional ADMS installed at the laboratory at site 1, connects to the telecommunications gateway of site 1. A secure bidirectional tunnel link (IPSec) was chosen as the type of connection, to comply with institutional requirements. Installation of such networks typically involves a comprehensive cybersecurity review of institutional practices, personnel, and equipment. After the initialization of the secure link, ADMS control signals and configuration inputs are sent from site 1 to site 2 through commercial off-the-shelf Real Time Automation Controllers (RTAC) from Schweitzer Engineering Laboratories [48], using the DNP3 protocol. The DNP3 signals are sent from the RTAC at site 2 to the real-time hardware-in-the-loop simulator which includes the model of the distribution system circuit, emulated IEDs such as reclosers and switches, and power electronic devices such as PV and BESS inverters. Signals such as acknowledgment and measurement feedback are sent from the emulated

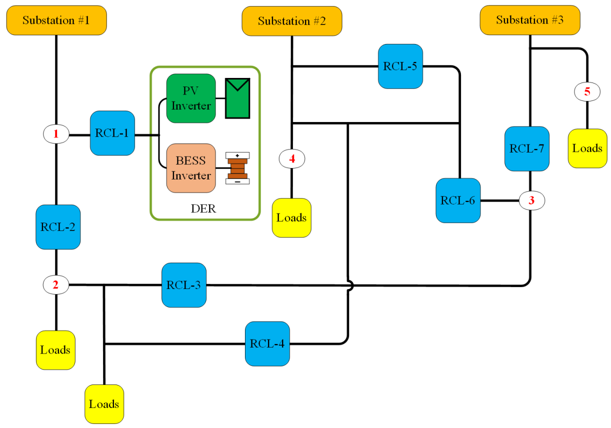

FIGURE 6. Aggregated model of distribution system implemented in DRTS, which includes DERs, loads and reconfiguration switches / reclosers.

devices in site 2 back to the ADMS at site 1 using the same bidirectional link.

C. DOCKER CONTAINER IMPLEMENTATION OF OPENFMB ADAPTER

A key element of a distributed control system is interfacing the distributed pub/sub harness with the SCADA systems. In this work, this is accomplished using containerized adapters. Specifically, OpenFMB adapters were implemented as containerized applications to facilitate interoperability and scalability. NATS (stands for ''Neural Autonomic Transport System'') is the pub/sub framework used for implementation of the adapters, because it is an open source, cloud native infrastructure messaging system [49]. The objective of this container is to establish secure communication channels to grid-edge power electronics and other IEDs. The OpenFMB harness shown in Fig. 1 is implemented as a Docker container (seen in Fig. 4), and installed on to a Schweitzer Engineering Laboratories 3360S hardened utility controller [50], working with the TyphoonHIL environment to publish and subscribe to data. After the HIL model is compiled and the power simulation is run, the simulation results are imported into a virtual machine where the Docker container is executed, and the measured electrical output quantities of the emulated IED or DER are published. These quantities can be accessed and read using a Visual Studio Code environment, as shown in Fig. 5. The harness is also accessible via a human machine interface (HMI), where measured quantities can be viewed and devices can be controlled.

D. POWER DISTRIBUTION SYSTEM MODELED ON DIGITAL REAL-TIME SIMULATOR (DRTS)

The distribution system used in this analysis consists in excess of 3,000 circuit segments, which makes it too large for most DRTS systems. As a result, the model was aggregated using the commercially available CYME Power Engineering software [51] to decrease the number of nodes to a computationally manageable figure, while preserving the model solutions. Specifically, the reduced order model yields the same power flow solution at key nodes, i.e. on either side of the reclosers. The results of power flow analysis on the full model and the reduced or aggregated model showed less than 1.0% deviation in powerflow solutions at the substation nodes and on either side of the reclosers. The reduced model of the system contains less than 200 sections and can be implemented in HIL. The use of DRTS yields high time-resolution results in real-time that accurately represents device- and system-level interactions. The reduced model as implemented in TyphoonHIL is shown in Fig. 6, along with the location of the DER installation and seven reclosers (labelled ''RCL'') for system reconfiguration.

E. POWER ELECTRONIC SYSTEMS DESIGN IN DIGITAL REAL-TIME SIMULATOR

A common inverter control loop representation for a current source grid-following mode of operation is shown in Fig. 7 and Fig. 8. The *abc-dq* transformation blocks calculate the *dq* reference frame voltages and currents which are then used, along with the reference active and reactive powers, to calculate the reference *dq* currents [52]–[54]. These are then compared with the *dq* currents calculated from output current feedback. The error is then applied to the PID controller which generates the modulation signals in the *dq* frame, which are transformed back into the *abc* frame.

The inverter control loop for grid-forming (voltage source) mode of operation is shown in Fig. 7 and Fig. 9. The desired grid voltage (v^*_{grid}) to be generated by the BESS inverter is provided as the output reference. The phase locked loop (PLL) block processes the reference signal to generate the phase angle of the voltage phasor, which is then used in the reference frame transformation blocks. The *dq* frame quantities of the grid voltage form the reference values for the outer voltage regulation loop of the grid-forming inverter. The output of the PID controller in the outer voltage regulation loop forms the reference current values, which are then compared with the measured currents in the *dq* frame. Like the grid-following mode, the error is then applied to another PID controller which generates the modulation signals in the *dq* frame, which are transformed back into the *abc* frame.

Hierarchically, outside the power converter control loops, grid-connected PV and BESS also possess grid support and protection functions to comply with standards such as IEEE 1547-2018 [27], [55], [56] and UL 1741 SA [57], and these functions include low and high voltage ride through, low and high frequency ride through, volt-var and frequency-watt droop control modes, and responding to abnormal voltage and frequency conditions. These outer loops such as droop control, an illustration of which is shown in Fig. 7, create the real and reactive power injection references with varying dynamic response depending on the power quality at the point-of-common coupling. Thus, by using a DRTS implementation that includes these outer control loops, the impacts of DER operation and protection schemes on the distribution circuit can be analyzed in real-time.

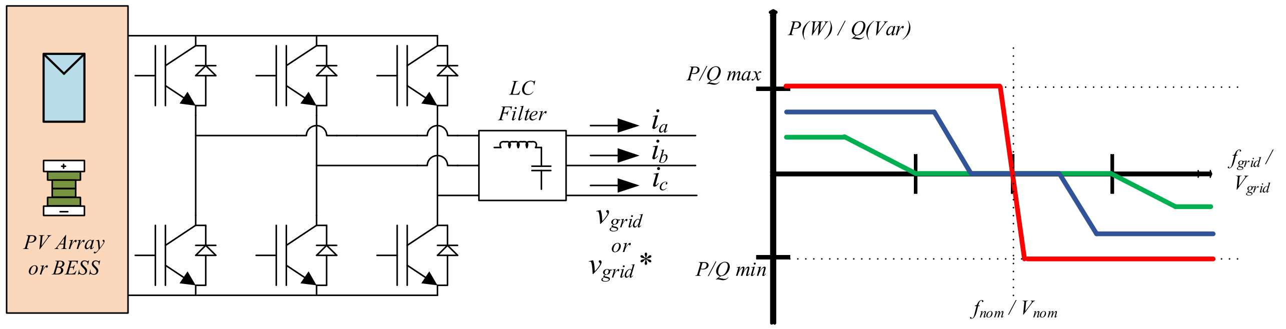

FIGURE 7. **Three phase two level inverter topology for PV or BESS integration; and grid frequency / voltage support droop curves with varying levels of real / reactive power injection responses (red: aggressive, blue: moderate, green: mild).**

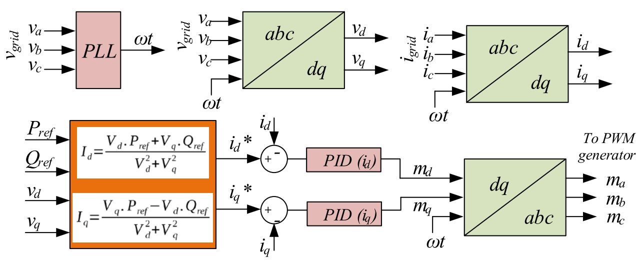

FIGURE 8. **Inverter controller block diagrams for current source, grid-following mode operation.**

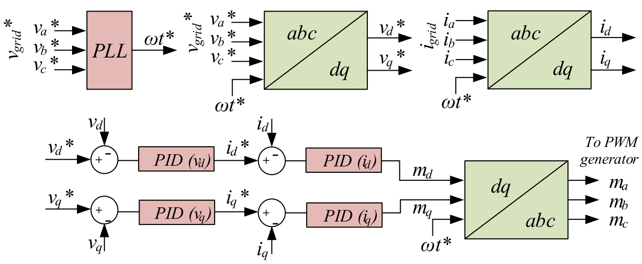

FIGURE 9. **Inverter controller block diagrams for voltage source, islanded grid-forming mode operation.**

IV. EXPERIMENTAL RESULTS

A number of multi-location experiments were conducted to validate the operation of the testbed and the capabilities to evaluate distributed controls. The connection from the ADMS at site 1, shown running in Fig 10, to the emulated IEDs at site 2 was verified by sending setpoint commands and receiving acknowledgement signals back. Fig. 12 shows the flow of traffic across the secure link captured using the open source tool Wireshark [58]. The propagation of signals from the RTAC at site 1 to the outgoing link, and from the RTAC at site 2 to the emulated IED, and the traffic in the opposite direction can be confirmed.

In the experiments presented here, an illustrative distributed control logic to select the recloser settings is programmed into the OpenFMB/TyphoonHIL layer at site 2, and commands to open and close each recloser are not sent from the ADMS. The browser HMI used to interface with the OpenFMB harness is shown in Fig. 11.

An analysis of distribution system performance under three grid operating conditions was performed: (1) baseline / best-case operating conditions (termed ''Blue-sky'') where

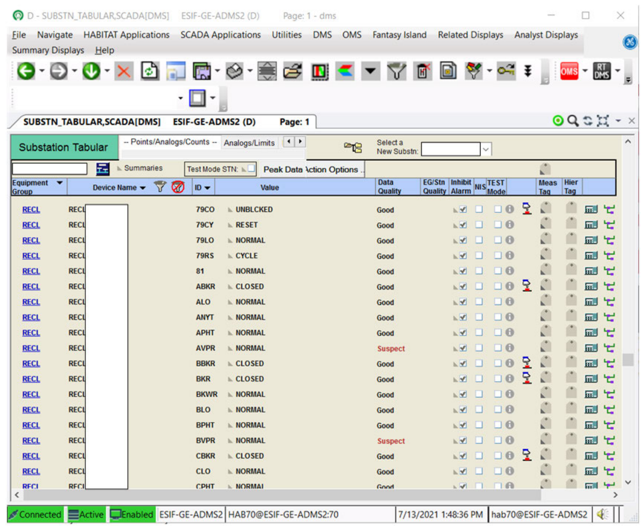

FIGURE 10. **View of GE ADMS operating at site 1 (NREL), of the real-world distribution system. Identifying tags have been redacted.**

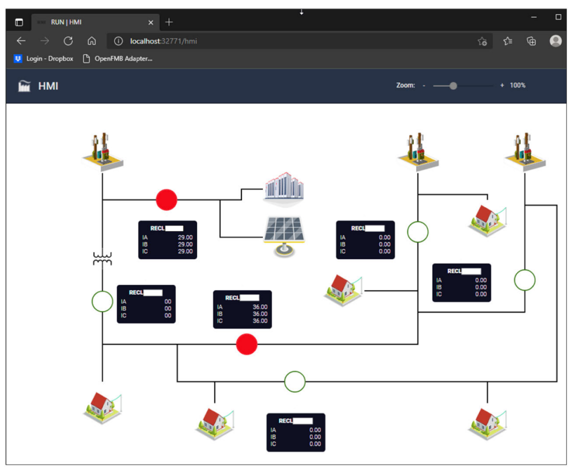

FIGURE 11. **HMI view of OpenFMB harness operating at site 2 (ORNL), of the real-world distribution system. Identifying tags have been redacted.**

the DER is switched off and all substations are operational and nominal, (2) moderate operating conditions (termed ''Grey-sky'') where the failure of one substation is indicated, and (3) poor operating conditions (termed ''Dark-sky'') where the failure of two substations is indicated. Under each

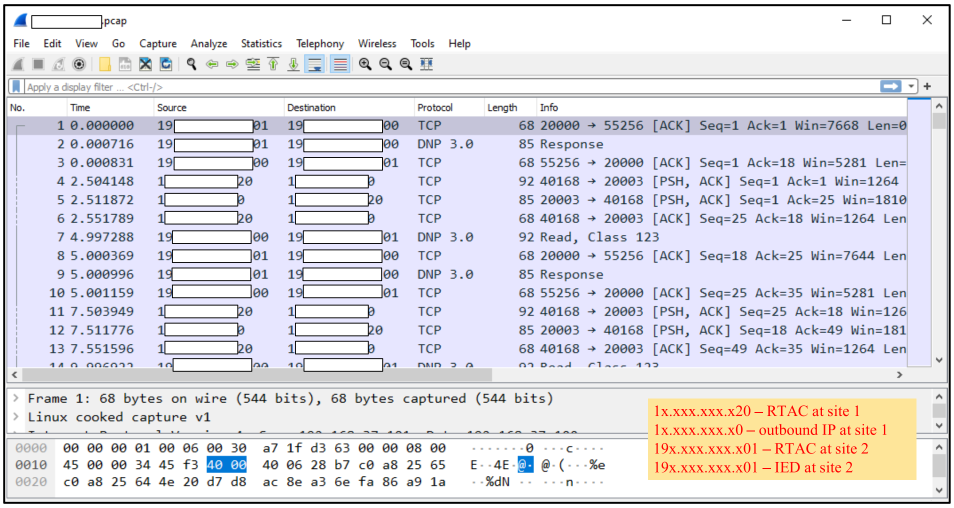

FIGURE 12. **View of bidirectional data traffic across the secure link between the ADMS and emulated devices, captured using the tool Wireshark. IP addresses have been redacted.**

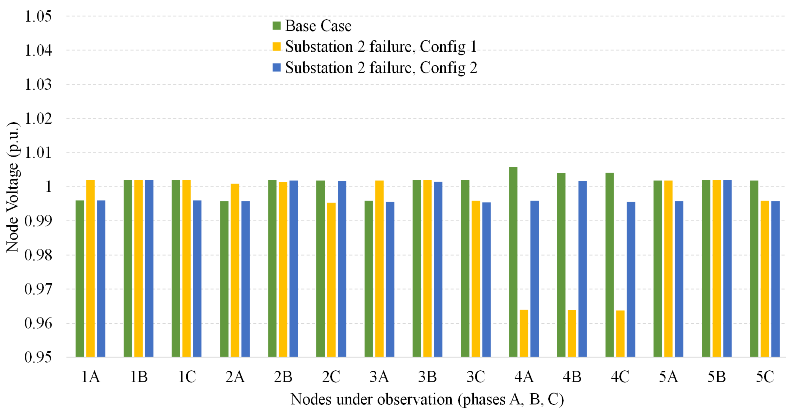

FIGURE 13. **Node voltages in simulated distribution system, observed under baseline and "grey-sky" conditions.**

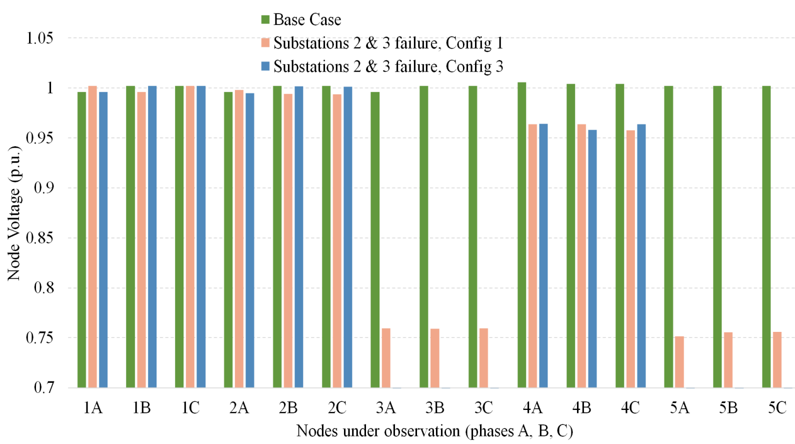

FIGURE 14. **Node voltages in simulated distribution system, observed under baseline and "dark-sky" conditions.**

operating condition, the distributed controller can analyze the power flow results, and can decide which recloser setting is to be used, to maximize service quality. In this implementation, the recloser settings can be managed at the ADMS level and the options for the recloser reconfiguration settings sent to the field assets via the communications infrastructure previously described. In the example studied, the recloser configurations shown in Table I are used. Nodes 1 through 5 indicated in Fig. 6 are observed and the per-unit voltages at these nodes are measured.

TABLE 1. Recloser configuration settings used in example study.

Operating Condition	Recloser Configuration
Baseline (Blue-sky)	RCL-1,2,5,7 Closed RCL-3,4,6 Open
Grey-sky, Config 1 (Substation 2 failed)	RCL-1,2,3,4,5,7 Closed RCL-6 Open
Grey-sky, Config 2 (Substation 2 failed)	RCL-1,2,3,5,6,7 Closed RCL-4 Open
Dark-sky, Config 1 (Substations 2 & 3 failed)	RCL-1,2,3,4,5,7 Closed RCL-6 Open
Dark-sky, Config 3 (Substations 2 & 3 failed)	RCL-1,2,4,5 Closed RCL-3,6,7 Open

The results of the simulated node voltages in steady state at nodes 1 through 5 are shown in Fig. 13 and Fig. 14. Imbalances in node voltages are observed due to unbalanced line impedances and single-phase loads in the simulated distribution system. Using these results, the distributed controller chooses the best recloser settings under the prevalent conditions, to provide power service and power quality for the greatest number of nodes possible. It is observed in Fig 13 that under "grey-sky" conditions (failure of one substation), both configurations 1 and 2 provide voltages within acceptable ranges, however, configuration 2 would be the better solution.

Nodes that experience unacceptable power quality metrics may be disconnected in simulation and the analysis can be performed again on other nodes. Fig. 14 shows the observed node voltages under "dark-sky" conditions (failure of two substations), where configuration 1 provides poor voltage quality at a number of nodes. Load shedding at nodes 3 and 5 (configuration 3) is required in order to remove any nodes with voltages outside nominal $\pm 5\%$.

The experimental setup can also be used to understand the transient behavior of devices, voltages, and currents in the system, as the reclosers are opened and closed. In this experiment, time delays were introduced to emulate real-world devices during operation. Fig. 15 shows the voltages at two nodes in the distribution system as the recloser settings move from one state to another, seen in the TyphoonHIL environment. Transient response is highly dependent on the devices used as references for modeling, and on the fidelity of the models themselves.

The voltage profiles obtained from these experiments show the impact of transmission system or substation loss on service quality in the distribution system. And by using accurate models of DERs and IEDs, a pub/sub harness using OpenFMB, and distributed control algorithms, the system operators can analyze the effects of system reconfiguration and interoperability among devices using real-time results. More importantly, this also enables the validation and/or redesign of distributed control algorithms such as FLISR, specific to individual distribution feeders. Since iterating and fine-tuning happens prior to field deployment, the refined solutions can greatly improve success in the field.

FIGURE 15. Transient behavior of two node voltages in the modeled distribution system, during recloser setting changes.

V. CONCLUSION

A multi-site securely networked experimental platform for the evaluation of distributed control and interoperability was presented in this paper. As installed DER capacity increases, deploying grid-edge intelligence and control is a potential solution for management of assets and to increase system resiliency. Interoperability among IEDs and DERs is a key requirement for this approach to be successful, and the OpenFMB pub/sub harness was presented as a tool to achieve this interoperability. As new grid functions and capabilities are added to these devices, concepts and prototypes must be evaluated before being deployed to the field *en-masse*.

The proposed multi-site testbed - which integrates facilities at utilities, vendors and other stakeholders - is a cost-effective and timely solution, as the power grid evolves rapidly. This platform provides a mechanism for utilities and grid operators to evaluate interoperability, control algorithms, and new circuit configurations before field deployment, which will enable the transition from a centralized grid to a more distributed control paradigm in an effective manner. The platform might also allow operators to perform analyses such as distribution system dynamics and protection for high DER penetration scenarios. The ability of some COTS devices to host the OpenFMB harness has also been demonstrated, significantly reducing the barriers to adoption [59].

ACKNOWLEDGMENT

Contributions to this project were achieved through the Grid Modernization Laboratory Consortium (GMLC), a strategic partnership between U.S. Department of Energy (DOE) and the National Laboratories, through support from the DOE Office of Electricity Delivery and Energy Reliability, and the Solar Energy Technologies Office. GMLC was established as part of the DOE Grid Modernization Initiative to accelerate the modernization of the U.S. electricity infrastructure.

The views expressed in the article do not necessarily represent the views of DOE or the United States Government.

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