PNNL-33471

Introducing the 9500 Node Distribution Test System to Support Advanced Power Applications

An Operations-Focused Approach

September 2022

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Executive Summary

The 9500 Node Test System is a representative section of distribution power system model developed as a part of the GridAPPS-D™ project, an effort funded by DOE as a part of the Grid Modernization Lab Consortium (GMLC) program. The test system was developed to fulfill a growing need to represent the rapidly evolving state of electric distribution systems by combining elements of legacy infrastructure systems, modern feeder topologies[1], and an anticipated future with smart grid technologies. It also provides a network model capable of supporting the simulation of operational scenarios such as the ones in a utility distribution control center.

This test system allows the evaluation of the performance of advanced power applications in real-time, such as one that simulates the operations of an Advanced Distribution Management Systems (ADMS), Distributed Energy Resource Management Systems (DERMS), etc. in a Distribution control center. This model is an extension of the widely used IEEE 8500 Node Test Feeder and is currently being validated to become an IEEE test case to help increase adoption and widespread usage among both academia and industry. It is a full-size model representative of a section of a utility's distribution system with multiple feeders fed from different substations. The model includes multiple distribution circuits, a sub-transmission system, multiple substations, behind the meter customer rooftop photovoltaics (PV), and multiple utility-scale distributed energy resources. To enable accurate simulations of operational scenarios, the 9500 Node Test System is designed to support procedure-based operations, with the ability to realistically demonstrate switching operations, feeder reconfiguration, adjustment of volt-var control equipment, dispatch of distributed generation, and response to planned and unplanned outages.

The 9500 Node Test System includes three radial distribution feeders with 12.3 MVA of average load, consisting of both medium voltage and low voltage equipment each supplied by a different distribution substation. The three distribution feeders are connected to each other through Normally-Open switches which can be closed when needed to simulate restoration scenarios due to a fault. One feeder represents today's grid with low penetration of customer-side renewables. The second represents a potential future grid with microgrids and 100% renewable penetration. The third has no customer generation resources, a district steam plant, and a utility-scale solar farm. The three diverse circuits were created to allow the simulation of both today's situation as well as potential future scenarios. All three feeders have customers connected by low-voltage secondary triplex lines.

This test system meets all requirements outlined in the report for creating a simulation environment that would enable discussion between key technical stakeholders as well as having the potential to accelerate operational application development and their subsequent testing and integration. The new model is a possible representation of what we believe the distribution grid may look like in the future: a high penetration of renewables, reconfigurable radial and mesh topology, numerous DERs, islanded microgrids, and significantly increased data and measurement density. The system supports both the solution of existing and newer algorithms but also enables the evaluation of applications in a realistic operational environment defined by task oriented procedural steps that represent the interaction between the control center operator and field personnel.

[1] Note: Modern topologies are differentiated from legacy topologies through the inclusion of smart reclosers, field measurements, and ability to transition between of radial and mesh topologies in the presence of a high penetration of DERs.

Acknowledgments

The 9500 Test System was developed under the GridAPPS-D™ program. The GridAPPS-D™ program is a program under the Grid Modernization Lab Consortium sponsored by the U.S. DOE's Office of Electricity, Advanced Grid Research. Its purpose is to reduce the time and cost to integrate advanced functionality into distribution operations, to create a more reliable and resilient grid.

The authors wish to thank Roger Dugan and Davis Montenegro from EPRI as well as Jing Xie from PNNL for contributing the independent power flow validation results included in Appendix C. The expert contributions of Ron Melton and Anjan Bose, detailed review by Kevin Schneider, and support by Jason Fuller in submission to the IEEE Test Feeders Working Group are also gratefully acknowledged.

Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
BTM	Behind the Meter
CA	Contingency Analysis
CEII	Critical Electric Infrastructure Information
CHP	Combined Heat and Power
CIM	Common Information Model
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DMS	Distribution Management System
DVR	Dynamic Voltage Regulation
EMS	Energy Management System
EPRI	Electric Power Research Institute
FLISR	Fault Location Isolation and Service Restoration
GIS	Geographic Information System
HSB	High-Side Breaker
ICCP	Inter Control Center Communications Protocol
IEEE	Institute of Electrical and Electronics Engineers
LTC	Load Tap Changer
LSB	Low-Side Breaker
MGMS	Microgrid Management System
N.C.	Normally Closed
N.O.	Normally Open
NREL	National Renewable Energy Laboratories
OMS	Outage Management System
OPF	Optimal Power Flow
PF	Power Factor
PNNL	Pacific Northwest National Laboratory
PQ	Constant Power, Constant Reactive Power Mode
PV	Photovoltaics
PV	Constant Power, Constant Voltage Mode
SCADA	Supervisory Control and Data Acquisition
SE	State Estimator
VVC	Volt-Var Control
VVO	Volt-Var Optimization

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1.0 Introduction

Decarbonization efforts are rapidly reshaping the electric grid. Significant increases in renewable penetration (at both the transmission and distribution level) and the emergence of new technical constructs such as microgrids are driving development of a new generation of advanced power applications. Development and evaluation of new applications and tools for this emerging distribution system require a robust, flexible, and scalable simulated real-time control center environment, such as that provided by GridAPPS-D [1]. The GridAPPS-D platform, APIs, and advanced applications were developed through an effort funded by DOE as a part of the Grid Management Lab Consortium (GMLC) program to provide a simulation environment reflecting the anticipated of distribution systems that would 1) enable discussion between key technical stakeholders and 2) accelerate application development, testing, and integration. Such an environment also required an ideal synthetic power system that would combine elements of legacy infrastructure systems, modern feeder topologies, and be able to support new and anticipated future technologies. It would also need to provide highly detailed network modeling capable of supporting operational scenarios including weather data and load profiles. To this end, the 9500 Node Test System was developed as a representative section of distribution power system model developed as a part of the GridAPPS-D™ project, to test these applications and tools under operational conditions and circumstances.

Suitable models for evaluation and demonstration of advanced applications need to be able to simulate the operational performance of modern power distribution systems with high levels of distributed energy resource (DER) penetrations, flexible operational topologies (configurations), and increasing levels of Distribution Automation. A vast majority of openly available test feeders were developed to test the ability of various algorithms to solve a power flow for defined loads with various fixed network topologies [2]. Enhanced feeder models can be helpful to support the continued development of newer distribution applications and tools to test the impact of these changes. These models would also allow the creation of a standardized testing framework to support evaluation of new operational technologies and strategies amid increasing demands for improved operational efficiency, reliability, and resilience towards extreme events. A much-needed enhancement to the model, provided in this report, is to provide the basis to simulate distribution operations in a system with distributed resources supported by controls and sensing technologies to enhance grid operations during normal and abnormal grid conditions.

Although some test cases (such as the IEEE 13 node and 123 node [3]) are well-suited for debugging and initial algorithm development, they are not an accurate representation of a full-size distribution circuit, due to their small size and lack of supporting information regarding adjacent feeders. Meanwhile, network models such as Bay Area and other NREL synthetic networks [4] (each of which has upward of one million nodes) are far too large for many applications which are in the early development stages to process or solve in an efficient manner. A comprehensive summary of the available distribution test feeder cases (including the IEEE Test Cases, PNNL Taxonomy Feeders, EPRI Feeders, and NREL Synthetic networks) is presented in Appendix I, as well as in the literature [2], [5].

The currently available test feeders make it difficult to provide insights into requirements for new algorithms, especially when they will be deployed in operational control centers. The 9500 Node Test System was designed to support simulation of operational scenarios which includes sequential, procedure-based actions performed by distribution operators, dispatchers, and field crews (such as equipment maintenance, switching operations, and response to equipment failure). Advanced applications need access to models that can to support commonly occurring events, such as line faults, reclosure actions, fluctuations in DER output, and transitions between radial and meshed topology during network reconfiguration.

There is a lack of a standardized, model that supports testing and simulation of system operations actions and controls in a real-time control center environment. As a result, the vendor community is developing their own models to test the systems that they are delivering to their utility customers. The utility industry needs a common model to test and validate the algorithms, and if needed, also test against others in the marketplace before deciding to pick one or the other. This model also needs to be capable of representing a distribution network that has a sub-transmission network supplying multiple substations and feeders. The feeder models also need to support utility scale DERs, rooftop solar, secondary transformers, reactive power and voltage control equipment (capacitor banks, regulators, and/or smart inverters), reclosers, sectionalizers, and fuses enabling network reconfiguration in both radial and meshed topologies for restoration and load rollover. These features will allow for a complete simulation of the real-time control center actions.

Prior to this work, there did not exist an industry-accepted standard distribution system model that met the requirements identified above. The 9500 Node Test System was developed to simulate the real-time operational control center needs of a rapid evolving distribution power system, combining elements of legacy infrastructure systems, modern feeder topologies, and the anticipated future of smart grid technologies. As described in the sections below, the 9500 Node Test System provides not only a highly detailed network model with three feeders capable of supporting a wide variety of operational scenarios in a fully replicable real-time simulation environment [1] to compare and benchmark the performance of power flow solver and advanced power application algorithms (which is only possible on the same system under the same conditions).

The remainder of this document is organized as follows: Section 2 discusses the importance of realistic synthetic power system models and real-time simulation. Section 3 reviews current trends and use cases of advanced distribution management systems. Section 4 details the functional requirements for a new model from the standpoint of improving resiliency and reliability, increasing energy efficiency, enabling islanded operations, and supporting a data-rich environment. Section 5 summarizes the 9500 Node Test System and modeling features. Section 6 outlines the recommended radial basecase for power flow validation with different solvers, developing realistic operational scenarios, and benchmarking the performance of new algorithms. Section 7 concludes. Appendix I summarizes existing distribution test feeders. Appendix II details the iterative process used to derive the new 9500 Node Test System from the original IEEE 8500 Node model. Appendix III provides a list of available file formats for the model and simulation validation with OpenDSS and GridLAB-D.

2.0 Role of Synthetic Operational Models and Simulation

It has been long known that large-scale real-time simulators (capable of running models with at least 10,000 nodes in real-time) can rapidly accelerate the development and implementation of the next generation of technologies in the grid [6]. This change requires bringing the next generation of advanced power applications, smart grid hardware, and next-generation control schemes and the creation of a common platform for communication between researchers, regulators, engineers, executives, operators, manufacturers, technicians, and cybersecurity experts. Each of these stake holders have different focuses, and it is difficult to find a common language for resolving communication barriers. Figure 1 below presents the mental models and focus of a few key stakeholders in the development of new applications and technologies. Each of these actors have highly siloed areas of expertise, and consequently, it is difficult to establish a platform for the

Figure 1: A comparison of the siloed perspectives of various key technical players in the development of new advanced power applications and smart grid technologies.

sharing of knowledge, requirements, and lessons learned.

The creation of a real-time simulation environment with scenarios that are representative of both normal operations and emergency events is conducive to creating discourse, collaboration and mutual understanding between these key stakeholders. It also enables relevant stakeholders to create real-time interactive forums (including operating training and inter-disciplinary cyber drills) for explaining key technical issues and engaging in role-play without the stress and possibility of equipment damage associated with real-time decision making.

A framework for simulating real-time operations can further serve as a springboard for accelerating industry-wide technical development. New algorithms can be tested in a replicable environment to compare relative technical and computational performance benefits. Likewise, historical events can be reproduced and re-enacted with detailed analysis of operational errors, equipment malfunctions, incorrect control settings, and key lessons learned in a controlled environment. Such simulated events are an extremely valuable tool in training operators and evaluating the efficacy of new power applications in a mock control room environment, such as at the Electricity Infrastructure Operations Center at Pacific Northwest National Laboratory (PNNL), depicted in Figure 2.

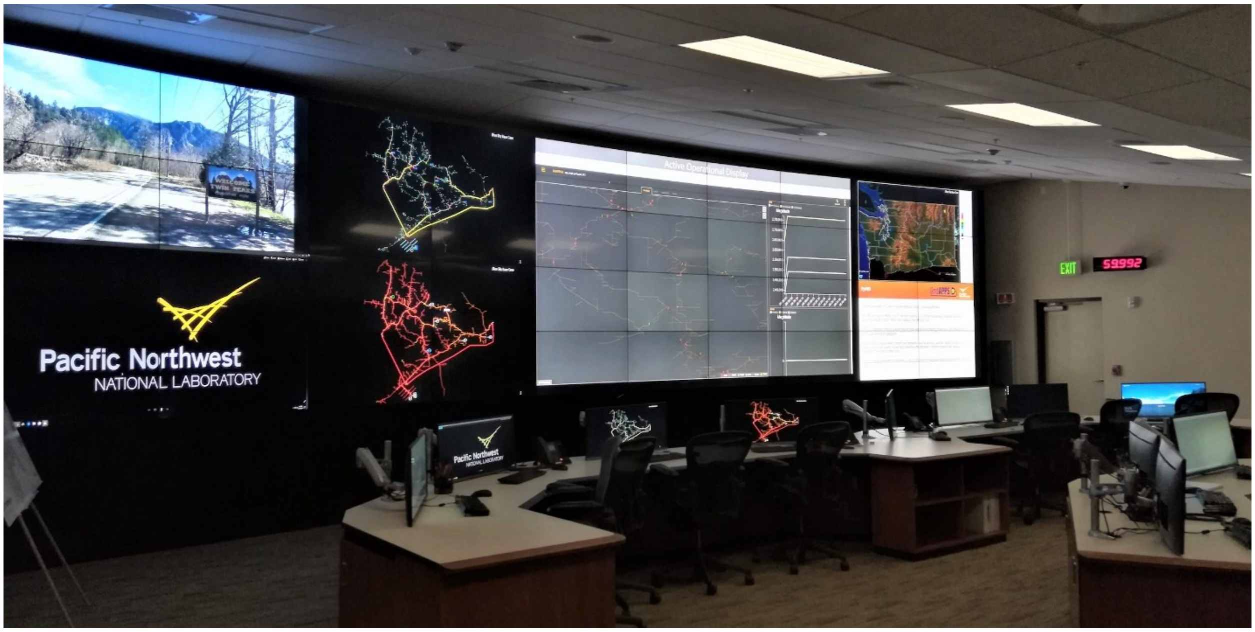

Figure 2: The 9500 Node Test System running on the GridAPPS-D™ simulation platform in the PNNL EIOC, December 2019. The simulation event was attended by application developers, utility engineers, and distribution operators, who engaged in a two-day discussion of advanced power applications.

Realistic power system models are essential for creating accurate, valid simulations. However, power system model and display information for the North American bulk electric transmission systems and distribution systems are now generally handled as Critical Electric Infrastructure Information (CEII). CEII can only be shared on a strict need-to-know basis with Non-Disclosure Agreements between utilities, vendors, and consultants. Synthetic power system models and synthetic software displays have the advantage that they do not contain any CEII and can be openly shared between researchers in both industry and academia.

Prior to the work presented in this document, there did not exist an openly available test feeder model that met all the requirements for creating a simulation environment reflecting the anticipated of distribution systems that would 1) enable discussion between key technical stakeholders and 2) accelerate application development, testing, and integration. The ideal synthetic power system would combine elements of legacy infrastructure systems, modern feeder topologies, and be able to support new and anticipated future technologies. It would also need to provide highly detailed network modeling capable of supporting operational scenarios including weather data and load profiles. To this end, the 9500 Node Test System was developed.

3.0 Current Trends in Distribution Operations

Electric power distribution systems have been traditionally designed for passive operation, where potential issues including protection, voltage regulation, reconfiguration are all identified and mitigated at the planning stage. Due to limited observability and controllability in a typical distribution system, they are usually designed and built to operate within the set of expected and credible scenarios. As a result, when the system experiences scenarios that were not considered at the planning stage, the operational outcomes may prove less than optimum.

With the rapid integration of medium and high penetration levels of DERs and responsive loads, distribution systems are rapidly transforming into complex systems capable of a broad range of operational scenarios covering both normal and emergency modes. A critical aspect of this change has been due to the large amount of demand and generation uncertainty introduced into the system, leading to new operational challenges [7]. These challenges include (1) 2-way power flow (2) widely varying generation coming into the system from the radial portions of the network (3) variability in distribution level congestion and overloading, and (4) voltage and power quality issues. In addition, the electric power distribution system is also facing increasing operational challenges from increasingly severe weather events (resulting in prolonged outages) [8] [9] and stricter regulatory requirements [10] [11] for increased reliability and resilience levels. Overbuilding the distribution system to handle all variations is neither appropriate nor financial prudent. These dynamically varying operating conditions require advanced approaches for distribution system operations supported by newer algorithms and mechanisms to solve them.

3.1 Emerging Distribution System Paradigm

There are several trends and technologies that will address the challenges discussed above. Emerging distribution systems are including Behind-the-Meter (BTM) assets, Internet-of-Things (IoT) devices, distributed sensors, and other devices capable of remote decision-making by themselves. These devices, if leveraged, have the potential to enable significantly higher levels of measurement, control, and automation for the utility's distribution operations by providing enhanced levels of system observability and controllability throughout the entire value chain all the way from substation equipment to customer devices, [12]. This motivates the requirement for a sophisticated operational model capable of supporting advanced applications to manage distribution systems operations and operations-planning, spanning the entire range of operational conditions from normal to alert (stressed) to emergency and blackout (failed).

An Advanced Distribution Management System (ADMS) is a software platform that supports grid management and decision support applications to address the growing operational challenges to ensure reliable, resilient, and economic operations [13]. The ADMS is an enhancement over the DMS of the past by adding new and improved advanced grid management applications. ADMS integrates the three core modules of Distribution Supervisory Control and Data Acquisition (D-SCADA), Outage Management System (OMS), and Advanced Applications through a single-common power system model and user interface. This integration provides a unified reference of the As-Operated state of the power system (described in Section 3.2) for each of the core ADMS modules. In addition, an industry-standard ADMS allows for the integration of new applications that can readily access information from various systems, including (but not limited to) Distributed Energy Resource Management System (DERMS), Advanced Metering Infrastructure (AMI), Customer Information System (CIS), Energy Management System (EMS), Microgrid

Management System (MEMS or MGMS), Geographic Information System (GIS), and other grid-edge systems which could be either utility-owned or customer-owned. Additionally, ADMS is well suited as a platform [1] to provide an interface that will integrate with future systems mitigating some issues of legacy systems. The GIS is the main source of the power system model providing key information such as 1) components in the power system model, 2) component names (ID), 3) component location (latitude, longitude), 4) component specifications and values (such as resistance, inductance, and others), 5) connectivity (what are they connected to), 6) their symbology (how they should show up in a user interface), and 7) their rendering (how their connectivity shows up in the user interface). The GIS brings the as-built state of the system into the ADMS, which in turn maintains the as-operated state of the system.

In summary, the ADMS provides a control and communication-rich environment that integrates advanced applications, with consideration to the integration of DERs, microgrids, alternate control strategies, and diverse model-based and data-driven algorithms. All these functionalities work together to support the system operator in monitoring and operating the grid in real-time. A conceptual representation of an ADMS system is given in Figure 3. A short list of typical ADMS features is presented in Table 1 below.

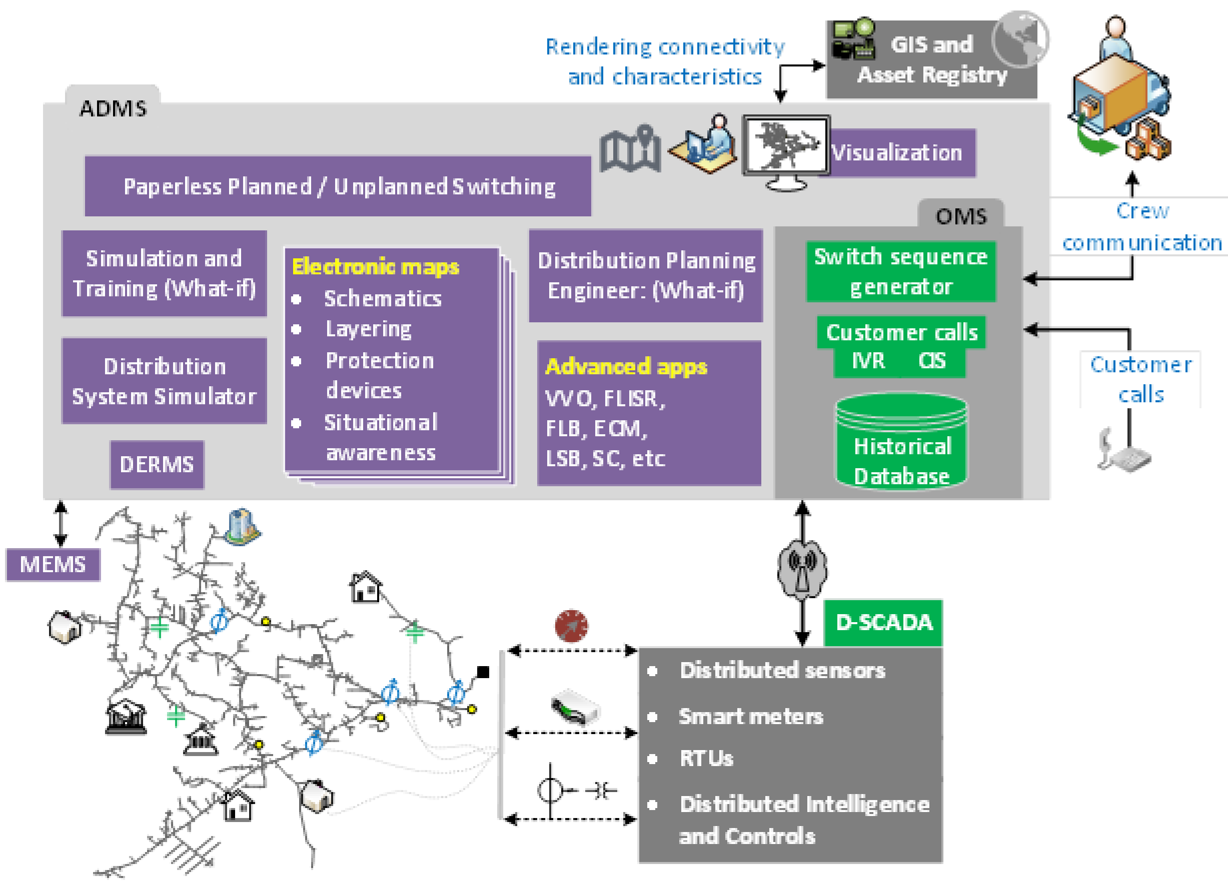

Figure 3: A Conceptual representation of the Advanced Distribution Management System (ADMS).

Table 1: A reference set of Sample ADMS Features

Core Modules		
D-SCADA	**OMS**	**Advanced Applications**
Scanner	Switching Sequence Generator	3-phase Unbalanced Power Flow
Control	Line and Circuit Tracing	State Estimator (SE)
Tagging	Field Crew Interface	Optimal Power Flow
		Contingency Analysis (CA)
		Volt-Var Optimization (VVO)
		Fault Location Isolation and Service Restoration (FLISR)
Cross ADMS modules		
Utilities	Alarms	Permissions and Roles
	Failover and Redundancy	
User Interface	Tabular Displays	One-Line Substation Schematic
	Geospatial One-Lines	
Parallel/Study Environments	Study Mode	Training Simulator

3.2 Types of Distribution System Models

There are three types of models generally used in an ADMS across all of three of the core modules (D-SCADA, OMS and Advanced Apps):

- **As-Designed Model:** This is the model put together designed by the designers working from the utility central offices using either an independent graphic workbench or one that is built into the GIS system. This model is the starting point for all work is also what is available in the GIS for all to use and see. Under normal circumstances, the owning system for this model is the GIS. The as-designed model is an intermediate model that is very often used to feed the planning models in a utility, at least until the information on the as-built conditions (see below) is used to update the model. Once the updates are all in, the correct model to use would be the "as-built" model.

- **As-Built Model:** This is the model of the power system that is actually implemented in the field by the field crew. A key aspect of this model is that all the switches and transformer/regulator/capacitor bank tap positions are in their normal positions. For the most part, it should be close to the as-designed model. However, local field constraints may result in differences, including equipment location, phasing, and connectivity. The change between the two models are mostly reflected in a piece of paper (at most utilities). Sometimes, a large period time passes for the changes to be reflected back into the GIS, leading to a discrepancy between the physical power system in the field and the model that is stored in the GIS. Under normal circumstances, the owning system for this model is also the GIS. The 9500 Node Distribution Test System represents the As-Built Model. All the switches/transformers/cap-banks will be in their default (normal) positions. This means that any power-flow (or other) solution on this as-built model should show near identical results and should be capable of being compared with each other. The As-Built model basecase is detailed in Section 6. Numerous As-Operated cases reflecting realistic operational scenarios under normal, alert, and emergency conditions have been developed for the 9500 Node Test System but are beyond the scope of this document. This is the model that would be fed into the ADMS or other similar operational systems.

- **As-Operated Model:** This is the actual model that is inside the ADMS. It contains all the switch/transformer/regulator positions in their real-time state in the field. This is a dynamic model and continues to change over time. Although the physical connectivity of the system does not change in this model, the electrical connectivity and behavior changes as the various components change their status. Under normal circumstances, the owner of this model is the ADMS and is used by all the subsystems – the advanced applications (FLISR, VVO, 3-ph unbalanced power flow and so on), OMS, and D-SCADA. This is also the output of the operational systems, and as a result, the information from these operational systems is also fed into other corporate systems for other business and technical analyses.

An exception to the normal operating modes defined above are when it comes to parallel/study environments such as study applications and/or the training simulator. These environments can be initialized from any of the models described above – and it will depend on the kind of analysis being performed.

A key point to consider is that all the modules in an operational system are using one copy of the model – they start with the As-Built model which turns into an As-Operated model as time moves forward and the status of devices changes and various flows and other values (e.g. transformer tap values) get calculated. In the real world, there could also be non-utility applications that do not have access to the utility GIS. During these circumstances, there would be some kind of agreement between the utility and the independent participants on model sharing – which brings in the need to for standards to make eh sharing od models easier for all. In a specific platform such as GridAPPS-D™ (or other set of advanced power applications), all the applications will be working off the same copy of the As-Operated model so that the System Operator is getting a single and consistent view of the system at all times.

3.3 Core Differences between Transmission Operations and Distribution Operations

A set of key differences exist between transmission and distribution operations. The system used to support transmission operations is the Energy Management System (or EMS) whereas the ADMS is mainly used to support operations of the distribution system. As a result, there are several differences between the two software systems.

The technology behind an EMS has been mature for more than 30 years now [13]. Fundamentally this system is designed around analysis of the transmission system which is modeled as a balanced network (a positive sequence one-line representation) of transmission lines and large generators, which are connected through substations. Also, historically, Transmission models was historically more detailed because that is where most of the assets were. These models supported both planning and operations.

Distribution system planning and operations was relatively simple until 20-30 years ago when unbalanced solvers became available. It was then further accelerated with the deployment of Smart Meters and Smart Grid technologies, which were typically installed at the distribution feeder level. Until these changes came into effect, much of distribution operations was focused on managing planned and unplanned outages. For the most part, this is continuing. As a result, distribution operations are still more process-centric (workflow-based) than transmission operations. The fundamental work that happens in the distribution control is in support of planned and un-planned work [13].

Transmission grids tend to be better outfitted with sensors and controls with mostly (if not all) of them located within a substation. The number of measurable points is greater than the number of measurable states. This results in a fully observable system with a small level of measurement redundancy. On the other hand, the number of sensors in a distribution system is significantly lower (but increasing). While most of these are located in a distribution substation, more and more of them are also being directly installed on the feeders well outside a substation. In addition, the number of remote (SCADA or otherwise) controllable points is also substantially lower for distribution feeders. Lastly, a significant percentage of sensors and switches in the field (outside substations) are not SCADA remote-controllable and need to be manually controlled by field personnel.

Next, clearance management and creation of switching orders are tasks performed by both transmission and distribution system operators, but the amount of planned work that happens in the distribution system is several orders of magnitude greater than that in a transmission system. This is a result of the fact that distributions systems have an order of magnitude[1] more conductor miles than transmission systems, and that the majority of end-use loads are commented at the distribution system. As a result, distribution system operators spend a significantly larger amount of time on

- Clearance management – The approvals required to isolate some equipment to perform maintenance (or replacement) work on it.
- Switching orders – The set of switching steps needed to be performed to isolate the equipment for which clearance has been obtained and to reenergize the component back in, after the work has been completed.
- Energizing new loads – adding new homes, new housing developments, new apartment complexes, new commercial buildings and so on.

Whether the switching order is being developed to isolate a component or to reconnect it back into the system, it goes through a series of reviews and approvals before it can be executed. These reviews are conducted to ensure the safety of field crew as they are working on the devices in the field. In addition, if the as-operated state of the network has changed since the time the switching order was developed, the process is repeated all over again. This step is further complicated by the fact that may of the steps in executing a switching order requires a field crew already positioned at the location to perform the step. As a result, extensive coordination and proper communication are essential between the system operator and the field crew.

[1] https://www.aep.com/about/businesses/transmission - Transmission miles at AEP = 40,000 miles
https://www.aep.com/about/businesses/opcos - Distribution miles at AEP = 219,000 miles

The distribution system is disproportionately affected by most storms and vegetation, which result in outages of several hundreds of thousands of customers created by possibly dozens or hundreds of downed lines. Restoring the system after numerous outages requires all the attention of the system operator(s) and the support of advanced power applications. The first step is identifying the fault location and extent of the fault (which feeders, which customers, etc.) during a storm or in an outage situation. Switching orders are then executed to isolate one or more components so that the field crew can safely work on the system in a de-energized state.

Identification of the faulted section of the feeder typically use devices such as FLISR which can be set up to work in a centralized, decentralized, or distributed configuration. However, to get the exact location of the fault, requires human intervention who may need to patrol the faulted section of the line to understand what actually caused the faulted condition (wire-on-ground, car-hit-pole, tree-fell-on wire, or something else) and where it was caused. These actions require a high degree of interaction between the operator and field personnel. When the problem is fixed by the field crew, another set of switching orders will be needed to bring power back to the affected people. Once the overall problem is solved, then another set of switching orders are executed to bring the system back to its normal operating state which will be different from the storm restored state.

Much of this work also includes switching orders that need to be treated just as planned work (see above). Switching orders are still created manually for the most part at most utilities using specific tools such as graph-trace methods (tracing where the feeder is fed power from). Newer power applications also have newer tools such as automatic switching order creators, but they are not yet in common use at utilities.

As a result, much of the complexity within an ADMS is focused on this manual intervention between the operator and field personnel and is built within the OMS (Outage Management System) subsystem of the ADMS. The OMS and D-SCADA systems tend to be the two most expensive components of the ADMS.

4.0 Functional Requirements of a Test Feeder that Supports Distribution Operations

This section provides a functional description of the capabilities that are required of a synthetic test feeder suitable for accelerating application development, testing, and integration of advanced power applications. As discussed in Section 2, the ideal synthetic power system would combine elements of legacy infrastructure systems, modern feeder topologies, and support current and emerging power distribution system needs and technologies. The test feeder functional requirements are framed around current and emerging distribution operations' needs, namely 1) improving resilience and reliability, 2) increasing energy efficiency, 3) enabling multi-point dynamic islanding, and 4) supporting a communications and control-rich environment.

4.1 Improved Resilience and Reliability

One of the most common motivations for utilities to adopt smart grid technologies and implement advanced power applications is to increase the reliability and resilience of the grid. Such investments are aimed at decreasing restoration times following outage events, reducing the total number of affected customers, improving overall service reliability, minimizing customer losses from power disruptions, and achieving cost savings from automatic switching actions. Increasing the reliability and resilience of distribution grids can be achieved by increased distribution automation, hardening the grid, and distributed generation. In developing a new test feeder, all three methods were considered and implemented.

In the future, the distribution system will rely heavily on distribution automation (e.g.. using automated switching, Volt-VAR optimization, and FLISR schemes) and advanced metering infrastructure (AMI). A representative test case must contain not only a set of fuses, sectionalizers, and reclosers to enable network recovery and reconfiguration, but also multiple substations to enable load transfer between adjacent feeders. These topological features enable the new test case to validate the ability of advanced power applications to respond to faults, overloads, and equipment failures.

These same features also allow for alternate network paths to be created so that when faults are isolated by system protection devices, outaged customers can be moved to non-faulted sections of the feeder and re-energized. The desired test case must contain multiple loops with normally open sectionalizers and/or reclosers to support network reconfiguration and load transfers.. The possibility of multiple restoration paths introduces elements of decision-making to determine an optimal restoration plan, which further challenges new and existing advanced power application algorithms to ensure scalability and convergence.

Finally, it is anticipated that future distribution grids will contain large amounts of distributed generation, which can possibly be leveraged to re-energizing load during severe storms or possible cyber-physical attacks.

4.2 Improved Energy Efficiency

Utility load is increasing at a rapid pace due to an increased focus on electrification – new electric load from EVs and gas to electric conversions among others. The normal approach to support this increased load is by enhancing and extending the grid and supporting the new need for energy with new procurements. This is now changing as utilities are facing increased pressure to do more with less with utilities looking at new and innovative mechanisms to to increase the energy efficiency of distribution systems. In response to this, utilities are making investments in both physical equipment and power applications to reduce losses. Physical equipment investments include installing switched capacitor banks, reconductoring distribution lines, multi-phasing, installing new substation transformers, and upgrading other substation equipment [14]. Advanced power applications, such as volt-var optimization (VVO), dynamic voltage regulation (DVR), and feeder voltage reduction can help improve overall efficiency of the electric distribution system [15], , lower the peak electrical demand, promote energy conservation, andreduce electrical losses . The advanced power application functions listed above determine optimal settings for voltage regulators, capacitor bank controllers, and smart inverters to accomplish the objectives described above. Additionally, it is anticipated that future power application algorithms will also consider feeder and phase reconfiguration through switching actions during normal operating situations to improve feeder voltage profile, reduce unnecessary VAR flows, respond to changes in loading conditions of the network with proliferation of DERs, and reduce system losses.

To validate these emerging features of the power distribution systems, it was determined that the test system model needs to include a suite of controllable devices that can be optimally coordinated to demonstrate the ability of new algorithms to improve the energy efficiency of realistic distribution networks. Further, the test system needs to reflect the practical nature of these upgrades where both new and legacy technologies will co-exist.

4.3 Intentional Microgrid Islanding

The potential for microgrids in improving resilience of the distribution systems during extreme events especially in serving the critical loads is widely recognized by the power community [16]. Lately, the concept of intentional islanding of parts of the distribution system using DGs with grid-forming capability (i.e. the ability to create a synchronous 60Hz grid frequency and to serve as the system slack bus) has been extensively explored with over a hundred recent studies reviewed by [17]. Along those lines, the concept of multi-point microgrid islanding and dynamic sizing has been developed in response to the need to serve the feeder's critical loads during extreme events. Moving forward, it is believed that the ability to create in real-time, islanded distribution systems to enable the utility to continue to support parts of the distribution network under normal or extreme conditions, will be integrated into the utilities' portfolio of action.

It was determined that the new test feeder must include several utility-scale DGs that can support islanded operations. The new test system needs to support the possibility of forming multiple islands throughout the distribution system using multiple DGs to enable testing and validation of dynamic multi-point and single-point islanding algorithms.

4.4 Communications and Control Rich Environment

The test feeder definition comprises the power delivery infrastructure, along with loads and resources. Some traditional elements on the distribution system use local autonomous controls, for example, tap changers and switched capacitor banks. Only a few are controlled remotely, for example, feeder breakers and some switches or other devices connected to SCADA. In power flow analysis, those autonomous control modes have been built into the software, while remote controls are often represented by command scripting. As modern distribution systems become more automated, and incorporate more active devices (such as responsive loads and smart inverters), it is necessary to represent the control and communication infrastructure more explicitly for several reasons:

- Interactions between devices may pose difficulty to the power flow solution. If the solution does not converge, the user needs to know whether the problem is numerical or if it indicates a real-world system instability. Simple and idealized models of the communication and control cannot provide this level of confidence.
- The costs of purchasing, deploying, connecting and maintaining the sensors, controls and communications for a more automated system would become a more important factor. The tasks of distribution planning and analysis are no longer complete with modeling just the power delivery components.
- Performance and reliability of the sensors, controls and communications may now influence the reliability and quality of electric service more directly. The impacts of data and communications systems on resilience would then also become important.

Future versions of any test feeder may include scenarios with different levels of control system build-out, performance and outages. These may pose additional challenges to the analytical solvers. However, distribution system analytical tools do not presently include communications and controls, other than by ad hoc scripting as mentioned above. Co-simulation with other tools, like NS-3 [18], may fill the analysis gap but this raises a new requirement to define and build a communications and control model to complement the power flow model.

The Common Information Model (CIM) [19] has some support for SCADA and Inter Control Center Communications Protocol (ICCP) at the transmission level, but it has not been used very much at the distribution level and may not cover all use cases on the distribution system. For example, the user may wish to investigate communication routes and sensor vulnerabilities in detail. Furthermore, a standard API for control actions and a standard method of representing custom control logic would enable 1) repeatability of simulation results between different research teams and 2) more economical deployment of new applications to the field. As work progresses to meet these new requirements, the 9500 Node Test System would provide a suitable test bed because of its configurability and its diverse control elements.

4.5 Summary

To reflect these requirements in the 9500 Node Test System, a combination of new and legacy volt-var equipment and distributed energy resources was deemed necessary, with different portions of the feeder reflecting the different levels of “smartness.” To accomplish this, a concept was developed of a feeder with three different regions. First is a New Neighborhood with 100% residential PV penetration (with smart inverters for voltage support), battery energy storage, and micro-turbine distributed generators (DGs), enabling extended operations as an islanded microgrid and enable study of reverse power flow situations when large amounts of rooftop PV generation back-feed into the sub-transmission grid. The second region is the Old Town neighborhood that does not include any new technology and mostly includes legacy voltage control devices, including a CHP district heating steam plant and 3-phase capacitor banks. The rest of the distribution system is populated with 10% penetration of rooftop PVs with smart inverters, along with traditional voltage regulators and capacitors banks for managing the voltage profile that can be used in conjugation with smart inverters to validate advanced applications for economic operation.

5.0 Summary of the 9500 Node Test System

The 9500 Node Test System is a large model incorporating elements of legacy systems, modern feeder topologies, and future smart grid technologies, which are grouped into representative regions within the feeder. The model includes multiple substations and extensive penetration of both customer rooftop solar and utility DERs. The model is designed to test the ability of advanced apps over a wide range of typical distribution operations and grid conditions. Key highlights and equipment of the 9500 Node Test System are presented in Figure 4 in a semi-geographical context.

Figure 4: A feeder plot colored by topological isolation illustrating the boundaries of the S1, S2, and S3 sub-feeders overlaid on a semi-geographic view of DERs, rooftop PV, and volt-var control equipment assets.

The 9500 Node Test System was developed in response to a series of new model features that were identified as necessary to enable demonstration of the ability of new advanced power applications to a) improve resilience and reliability, b) increase energy efficiency, c) create intentional microgrid islands, and d) operate in a communications-rich environment. The specific requirements that motivated and shaped the development of the 9500 Node Test System were described in detail in Section 4 and summarized below:

1) A right-sized distribution system model with multiple feeders supplied by multiple substations, enabling feeder reconfiguration, load rollover, fault isolation, and transitions between meshed and radial topologies through a combination of normally-open tie-switches and normally-closed sectionalizing switches
2) Incorporation of numerous controllable devices, including switches, capacitors, regulators, smart inverters, DGs, and battery storage in a sizable unbalanced distribution system.
3) Inclusion of customer rooftop DERs with smart inverters and different load types, along with legacy voltage control devices (voltage regulators and capacitor banks) to demonstrate the impacts of DERs on distribution feeder and the volt-var capabilities from emerging power electronics devices.
4) Incorporation of a mix of utility-scale, dispatchable grid-following and grid-forming DGs in the network that can provide grid support services under different scenarios. This will enable testing of advanced applications to extract different grid services such as voltage regulation, restoration, and intentional islanding.
5) Ability to intentionally island parts of the distribution network to support critical loads using distributed generators during emergency conditions. These capabilities will help evaluate advanced measures taken to improve the resilience of the distribution systems to the extreme events via intentional islanding.

None of the currently available distribution test feeders, which are described exhaustively in Appendix I, meet all the requirements listed above. Although existing distribution test feeders can be modified to include different aspects of smart grid upgrades and distribution automation features [20], none of them provide a replicable platform for researchers, utilities, and application engineers to develop and test new solvers, control strategies, and applications in a rapidly changing environment., there clearly exists a need for a dedicated test feeder model that is comprehensive enough to represent the emerging power distribution grid of the future [2].

Consequently, it was deemed necessary to create a new model representing the anticipated smart grid of the future, with a high penetration of renewables, meshed topology, numerous DERs, islanded microgrids, and significantly increased data and measurement density. The desired feeder needed not only to support the solution of existing and newer algorithms but also enable evaluation of application in a realistic operational environment, which is rich in procedural steps that generally define the interaction of between the control center operator and field personnel

The 9500 Node Test System was derived through a modernization and expansion of the IEEE 8500 Node Test Feeder, which is well recognized throughout research and academia. A series of modifications (described exhaustively in Appendix II) were made focused on improving the ability of the model to be reconfigurable, controllable, and demonstrate usage of anticipated smart grid technologies in a real-time simulation environment. Table 2 below presents a comparison of the capabilities of the original 8500 Node Test Feeder and new 9500 Node Test System.

Table 2: Comparison of Attributes for the IEEE 8500 Node and 9500 Node Models

Attribute	8500 Node Test Feeder	9500 Node Test System
Right-sized	Y	Y
Controllable	Y	Y
Reconfigurable	N	Y
Customer DERs	N	Y
Utility-scale DERs	N	Y
Islanding	N	Y

The 9500 Node Test System is a radial distribution feeder consisting of both medium voltage and low voltage equipment supplied by three sub-transmission substations. High-side and low-side breakers for all substation transformers and line breakers for all 69kV lines are included for realistic modeling of line and transformer protection schemes. However, it was determined that grounding switches on either side of each breaker for possible equipment replacement and maintenance were not needed for the goal of advanced power application development and testing. Figure 5 below presents a one-line view of the sub-transmission network, including 69kV lines, LTC transformers, and isolating breakers.

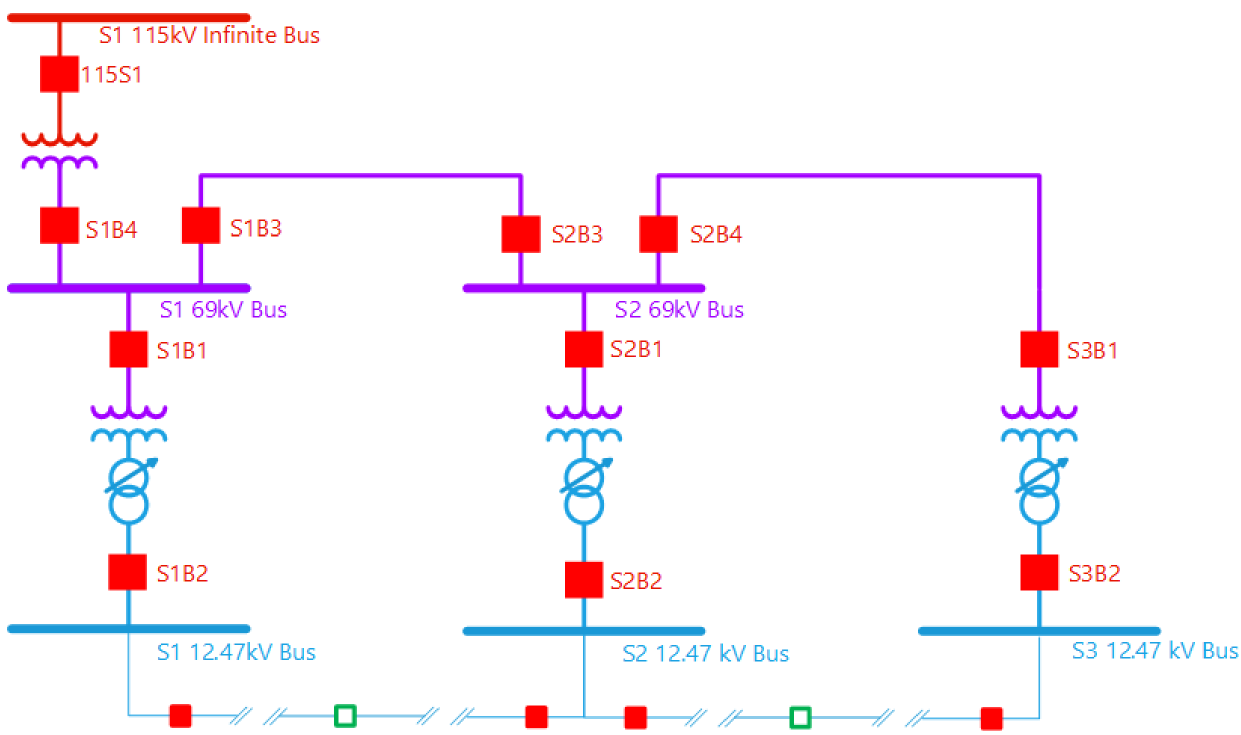

Figure 5: A one-line diagram of the 9500 Node Test System sub-transmission network showing high-side and low-side breakers on either side of the 115-69kV and 69-12.47kV transformers

As the name implies, there are approximately 9500 node points in the system for which voltages must be computed. There are numerous three-phase, two-phase, and single-phase nodes throughout the system at several different voltage levels, namely 115 kV, 69 kV, 12.47 kV, 480 V, and 120/240 V. Like the original 8500 Node Test Feeder, customer secondary service lines are explicitly modeled for each load, along with typical center-tapped split-phase secondary transformers, and unbalanced two phase customer loads, with a total of 1275 load buses in the feeder. Table 3 below summarizes the number of one-, two-, and three-phase buses and nodes, as well as the number of customer secondary nodes.

Table 3: Total Number of Nodes and Buses in the 9500 Node Test System

Type	Number of Buses	Number of Nodes
Three Phase	847	2541
Two Phase	3	6
Single Phase	1902	1902
Secondary Customer Buses	2550	5100
Total	**5302**	**9549**

The 9500 Node Test System is divided into three feeders, which can be topologically radial or meshed. The feeders are named S1, S2, and S3, and represent, respectively, a typical modern grid with some customer-side renewables, a future smart grid with microgrids and 100% renewable penetration, and a legacy system with no customer resources and a district steam plant. Several utility-scale distributed energy resources (DERs) are located in each feeder, which can operate in grid-forming or grid-following modes to either form islands supplying critical loads or support efficient and reliable operations in normal conditions. Table 4 summarizes the total load and number of distribution system components in each of the three sub-feeders.

Volt-var control is obtained through dispatch of DERs, rooftop solar smart inverters, and legacy equipment. The circuit contains one set of regulators controlling the feeder voltage at each substation in addition to the original volt-var control equipment retained from the IEEE 8500 Node Test Feeder, which include three poletop voltage regulators and four poletop capacitor banks.

Table 4: Available Control Resources in the Three 9500 Node Sub-Feeders

Feeder	No. of Customers	Load		No. of Regulator	No. of Capacitor	No. of DERs
		kW	kVAR			
S_1	268	3432.6	855.9	2	2	7
S_2	475	4803.1	1554.0	2	1	6
S_3	532	5432.8	1355.3	2	1	2
Total	**1275**	**13668.5**	**3765.2**	**6**	**4**	**15**

6.0 Recommended Radial Basecase

As a fully reconfigurable model, there are countless variations of possible As-Operated states of the 9500 Node Test System. As a result, it is highly desirable to create a single As-Built Basecase for model validation, development of realistic operational scenarios, and benchmarking of new ADMS algorithms.

6.1 Switching Configuration

In the basecase, the 9500 Node Test System is separated into three individual radial feeders supplied by the sub-transmission network. The feeder is divided by designating a set of normally open switches on each of main conductor paths, such that each feeder serves relatively equal amounts of load. Additionally, several switches are designated as normally open to break any topology loops within the feeders, including a set of underground cable phase-to-phase load transfer switches. Figure 6 provides a colorized feeder view illustrating the boundaries between the three sub-feeders, showing locations of DERs and volt-var control equipment. Table 5 summarizes the normally open switches in the feeder, their location, and role in creating a radial topology.[1]

Table 5: Normally Open Switches in the 9500 Node Test System Basecase

Switch Name	Feeder	Comment
WF856_48332_sw	S3	Underground cable single phase transfer switch
WG127_48332_sw	S3	Underground cable single phase transfer switch
TSW320328_SW	S2	Breaks single-phase loop in Industrial District
LN0653457_SW	S3	Breaks three-phase loop in Old Town
A333_48332_SW	S1 – S2	Three-phase tie switch between S1 and S2 (Industrial District)
A8645_48332_SW	S1 – S2	Three-phase tie switch between S1 and S2 feeders (Southeast)
V7173_48332_SW	S1 – S3	Three-phase tie between S1 and S3 feeders (North Section)
TSW803273_SW	S2 – S3	Three-phase tie between S2 and S3 feeders (Central Neighborhood)
TSW568613_SW	S2 – S3	Single-phase tie between S2 and S3 (Central Neighborhood)

[1] Note: Equipment names and node numbers will use a COURIER FONT to clearly identify these features for the reader.

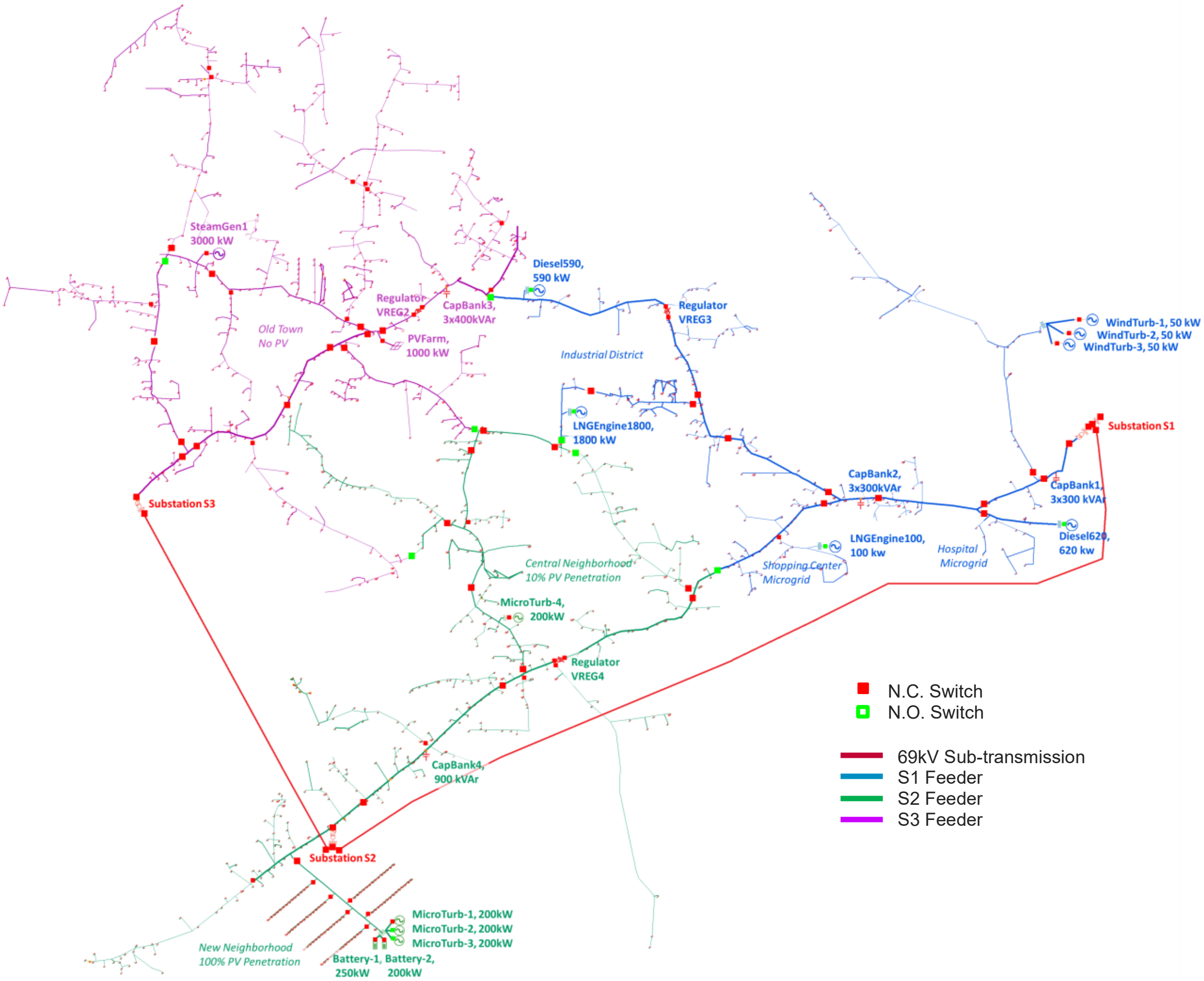

Figure 6: A feeder plot colored by topological isolation typical of operational control room graphic user interfaces illustrating the boundaries of the S1, S2, and S3 sub-feeders with DERs and VVO equipment labeled. Line thickness corresponds to conductor ampacity

6.2 DER Setpoints

The second set of status definitions necessary for defining the basecase is the generation and control setpoints for the utility-scale DERs in the system. Most of the utility-scale DGs are higher-cost peaking units that are only dispatched during capacity shortages, severe weather, or other operations in stressed grid conditions. The Old Town steam plant provides heat and service steam to nearby customers, and therefore remains near its minimum setpoint. Likewise, New Neighborhood keeps one microturbine running near idle to enable smoother transition from grid-connected to islanded mode in the event of an unexpected grid disturbance. A summary of the operating states and setpoints is presented below in Table 6. Since the As-Built model does not reflect dynamic conditions of load and weather variations, all rooftop PV resources operate at their maximum power point (100% possible irradiance), and all loads are set at their nominal values.

Table 6: Generation and Control Setpoints for Utility-Scale DERs in the Basecase

DER Name	Generation Setpoint	Control Setpoint	Equivalent Injection	
			P (kW)	Q (kVA)
SteamGen1	1000 kW	1.00 pu voltage	1000	-1049.5
PVFarm	100% irrad. (500 kW)	0 kVAR	1000	0
MicroTurb-1	50 kW	0.95 pf	50	16.4
MicroTurb-2	OFF	OFF	0	0
MicroTurb-3	OFF	OFF	0	0
MicroTurb-4	100 kW	0.95 pf	100	32.9
WindTurb-1	20 kW	0.95 pf	20	6.57
WindTurb-2	20 kW	0.95 pf	20	6.57
WindTurb-3	20kW	0.95 pf	20	6.57
Diesel620	OFF	OFF	0	0
Diesel590	OFF	OFF	0	0
LNGEngine100	OFF	OFF	0	0
LNGEngine1800	OFF	OFF	0	0
Battery1	OFF	OFF	0	0
Battery2	OFF	OFF	0	0

6.3 Application Benchmarking and Operational Scenarios

The 9500 Node Test System basecase is deliberately sub-optimal to demonstrate the potential level of improvement offered by advanced power applications focused on increasing energy efficiency, such as network reconfiguration, VVO, and DER dispatch. Although the switching configuration is near-optimal, voltage violations and losses can be decreased significantly through adjustment of DG setpoints, regulator taps, and capacitor banks. For example, adjusting only the voltage setpoint of the Old Town steam plant resolves all low voltage violations in the basecase and decreases both real and reactive power losses in the feeder, as seen in Table 7. Numerous other improvements are possible to further increase the energy efficiency of the feeder, decrease LMP, and so on.

Table 7: Increase in Energy Efficiency from Basecase from Modifying one VVC Setpoint

Steam Plant Control Setpoint	Min Voltage	MW Losses	MVAR losses
Basecase: V = 1.00 pu	0.931 pu	0.439 MW (4.84 %)	0.401 MVAr
Adjusted setpoint: V = 1.05 pu	0.957 pu	0.425 MW (4.69 %)	0.384 MVAR

The basecase also serves a starting point for creating numerous detailed operational scenarios designed specifically to test the capabilities of several categories of advanced power applications in real-time simulations with varying loads and weather, as well as planned maintenance, unplanned outages, and other realistic events. However, more detailed discussion of the application evaluation framework and real-time scenarios developed on the 9500 Node Test System is beyond the scope of this document.

7.0 Conclusion

This report presented the 9500 Node Test System as the first synthetic, operations-focused model of a distribution power system. It is anticipated that the model will find a wide range of potential applications for advanced power application development, testing, and benchmarking. It contains features representing not only the current state, but also the anticipated future of the distribution grid. Significant operational flexibility is enabled by the presence of multiple distribution circuits with normally-open switches, a sub-transmission system, multiple substations, reactive control equipment, customer rooftop PV, and multiple DERs of varying size and fuel sources. Coupled with the size of the model, it is anticipated that the 9500 Node Test System could serve as a springboard for discussions, information sharing, and knowledge transfer between acadaemia, industry, researchers, and utilities without any of the constraints of CEII data or proprietary models currently used by vendors for internal power application testing and demonstration.

The flexibility and focus on accurate modeling of distribution operations tasks will also enable the 9500 Node Test to serve as a basecase and platform for developing and sharing a wide variety of realistic operational scenarios. These scenarios can be used for benchmarking the performance and testing the response of advanced power applications to challenging real-world operating conditions. A set of about a dozen scenarios with associated switching orders have already been developed for a wide range of common tasks (including planned outages, faults, maintenance tasks, and DER optimization). These scenarios cover a range of weather profiles (blue/grey/black sky) and grid operating conditions (normal/alert/emergency). Each scenario was developed specifically to test the capabilities and response of one or more advanced power applications, such as VVO, DER dispatch, FLISR, etc. These scenarios and associated data sets will be made available in a future publication.

Additional variations of the model will also be derived using simplified line and load models to reduce the total number of nodes without changing the total feeder load, power flow characteristics, or overall topology. These intermediate sized models will be well-suited to initial application debugging, enabling developers of advanced power applications to determine if possible convergence problems of some novel algorithm are caused by the topological complexity of the model, numerical scaling issues, an algorithmic implementation error, or some other reason. It is anticipated that the reduced-size model variations of the 9500 Node Test System could be of great use to application developers.

The 9500 Node Test System is also well suited for integration with a detailed communications network model that would enable co-simulation with a platform, such as NS-3 [18]. Significant research advances could be attained by the combination of the detailed power system model that models components down to the customer meter and BTM equipment with a communications model representing individual AMI meters, future IOT sensors, smart appliances participating in demand response programs, poletop control equipment, and substation remote terminal units. Creation of such a combined model would enable numerous cyber-physical use cases, such as distribution system cyber-intrusion detection or detailed study of the impact of communications delays or bad data on power applications.

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Appendix A – Existing Distribution Test Cases

To provide the context from which the 9500 Node Test System was developed, a summary of the state-of-the-art is presented with short summaries of each of the available hypothetical distribution test feeders. The test feeders are categorized by the entity or working group responsible for reviewing and maintaining the data repository for each power system model.

A.1 IEEE Test Feeders

The first set of IEEE test feeders were originally created in 1992 [21] to solve the three-phase unbalanced power flow in radial systems. and provided a test for the accuracy of the distribution component models and the convergence characteristics of the program being tested. An updated version of the same test feeders and a simple feeder that can be used to test three-phase transformer models was published in 2001 [3]. These feeders represent the reduced order model of an actual distribution circuit and do not model the details of a distribution circuit at the secondary level. In 2010, two new challenging large models (the Comprehensive and 8500 Node Test Feeders) were added [22], [23]. In what follows, the characteristics of these test circuits are discussed in more detail.

1) 13-bus Feeder: This is a small distribution test feeder operating at 4.16 kV voltage level. It consists of a single voltage regulator at the substation, overhead and underground lines, shunt capacitor, and an in-line transformer. This feeder is relatively highly loaded and provides a good test of the convergence of the problem for a very unbalanced system.

2) 34-bus Feeder: This test system models a long distribution feeder located in Arizona operating at the 24.9 kV voltage level. It is a relatively lightly loaded feeder with two in-line regulators that are operated to satisfy ANSI voltage standards, an in-line transformer for a short 4.16 kV section, unbalanced loading with both spot and distributed loads, and shunt capacitors.

3) 37-bus Feeder: It is a three-wire delta underground system operating at the 4.8 kV voltage level. While this circuit configuration is fairly uncommon, this feeder was developed to test whether the software packages and algorithms can work on an unbalanced delta system. The feeder model includes delta configured underground line segments, spot loads, and two single-phase open-delta regulators at the substation.

4) 123-bus Feeder: This models a large unbalanced distribution system operating at the nominal voltage of 4.16 kV. It consists of overhead and underground lines with single, two and three-phase laterals, along with step regulators and shunt capacitors for voltage regulation. The feeder model is characterized by the unbalanced loading having all combinations of load types (constant current, impedance, and power). It also includes a few switches to allow for the alternate paths for the power flow via feeder reconfiguration.

5) 4-Node Test Feeder: This feeder was included 10 years after the original test feeders were published. The primary purpose of this test feeder is to provide a simple model for the analysis of all the available three-phase transformer connections under the different scenarios of balanced and unbalanced loads.

6) 8500-Node Feeder: This is a relatively large and realistic radial distribution feeder consisting of MV and LV (secondary) circuits [23]. Unlike other test systems, this feeder

also includes 120/240V center-tapped transformers that are commonly deployed in North American power distribution systems. Thus, it allows for users to interchange between the two versions of loading conditions: balanced (208 V) and unbalanced (120 V) in the secondary transformers. Voltage control equipment details were specified in [24], with the feeder including a substation LTC transformer as well as multiple poletop regulators and capacitor banks. The feeder was created to test scalability and convergence of power flow algorithms on a large unbalanced power distribution system.

7) Comprehensive Feeder: The comprehensive IEEE test feeder has been developed to validate the models of all distribution-level components and the convergence of power flow algorithms for multiple 1-ph, 2-ph, and 3-ph line geometries and transformer configurations [22]. Unlike IEEE test feeders developed until 2010, this test feeder present a diverse and detailed network where most of the available configurations and equipment are included such as overhead and underground lines, dissimilar transformers, step voltage regulators, induction machines, capacitor banks, and the mixture of distributed and spot unbalanced loads. The feeder is best suited for testing the ability of power flow algorithms to process different types of equipment in a small network, rather than real-time operations.
8) 342-Node Low Voltage Networked Test System (LVNTS): The 342-Node Low Voltage Networked Test System is a heavily meshed system representing the secondary networks deployed in urban cores in North America [25]. This feeder model was included to present the challenges posed to traditional power flow solvers and other distribution automation methods by non-radial distribution networks, several parallel transformers, and parallel low voltage cables.
9) NEV Test Feeder: This test feeder encourages the development of tools capable of modeling nearly all aspects of steady-state frequency-domain analysis encountered on distribution systems. Since, Neutral-Earth-Voltages (NEVs) are principally 3rd harmonic along with the fundamental frequency, it requires that the system must be solved at two frequencies. A few features of this test feeder are: three winding substation transformers with substation neutral reactor, line-neutral load connection, four circuits on the same pole sharing a common neutral, unbalanced third harmonic currents, and both line-to-neutral and neutral-to-ground voltages.

The IEEE test feeders and features are summarized in Table 8 below. None of the IEEE test feeder models include DERs in the base case. These feeders have been modified by researchers in accordance with the requirement for their algorithms. While that is an acceptable solution for validating algorithms, it limits the applicability of these test systems to serve as a benchmark for evaluating and comparing the emerging state-of-the-art methods on a common test system.

Table 8: Summary of IEEE Test Feeders

Feeder Name	Length	Nominal Voltage (kV)	Topology	Service Xfmr	Total Customers	Peak Load (MW)	N.O. Switches
IEEE 4 Bus	1.3	12.47	Radial	N	1	6.3	N
IEEE 34 Bus	94	24.9	Radial	N	24	1.6	N
IEEE 37 Bus	5.5	4.8	Radial	N	25	2.73	N
IEEE 123 Bus	12	4.16	Radial	N	114	3.8	Y
IEEE 8500 Node	170	12.47 0.240	Radial	Y	1177	11.1	N
Comprehensive Test Feeder	81.7	12.47 24.9	Radial	Y	36	4.17	Y
IEEE 342 Node	15.2	13.2	Meshed	Y	624	49.4	N
NEV Test Case	1.82	12.47	Radial	Y	1	8.9	??

A.2 EPRI Feeders

EPRI test circuits models are representative of actual circuits from various utilities to provide models for researchers interested in solar integration studies, testing power flow in a smart grid environment, and volt-var control. The characteristics for each of the feeders are listed in Table 9 below. Note that length is from substation to feeder end, not the total circuit miles.

The distributed photovoltaic project feeders J1, K1 and M1 are intended for investigation of hosting capacity and variable photovoltaic (PV) adoption scenarios [26]. The J1 and K1 feeders come with existing PV installations. M1 does not include PV, but it does include more detail in the secondary circuit, indicated by a higher ratio of customers to service transformers. Three other EPRI models, namely ckt5, ckt7 and ckt24, are included as part of the OpenDSS download and are documented within the software documentation [27].

Table 9: Summary of EPRI Distribution Test Feeders

Feeder	Length	Nominal Voltage (kV)	Topology	Service Xfmr	Total Customers	Peak Load (MW)	N.O. Switches	Total DERS
EPRI J1	18 km	12.47	Radial	816	1384	11.56	0	13
EPRI K1	7 km	13.2	Radial	308	308	12.75	0	1
EPRI M1	3.3 km	12.47	Radial	159	1470	15.67	0	0
EPRI Ckt 5	5.2 km	12.47	Radial	591	1379	7.28	0	0
EPRI Ckt 7	4.1 km	12.47	Radial	158	5694	42.2	0	0
EPRI Ckt 24	12.9 km	34.50	Radial	820	3885	52.1	0	0

A.3 PNNL Taxonomy Feeders

PNNL developed a taxonomy of 24 prototypical feeder models in the GridLAB-D simulation environment that contain the fundamental characteristics of non-urban core, radial distribution feeders from the various regions of the U.S. These synthetic test feeders characterize distribution systems in different regions of the U.S. A clustering algorithm was used for developing these synthetic test feeders based on the data from 575 actual distribution feeders from 17 different utilities. See [28] and [29] for more description of the PNNL taxonomy feeders. Some of their shared characteristics are:

- Mixtures of underground and overhead, nominal voltage levels, feeder lengths and numbers of customers were chosen to represent different regions and service territories.
- All of these feeders are radial.
- Most of these feeders are unbalanced, except for one example that serves large three-phase commercial loads.
- Many fuses and switches are included for segmentation; all are normally closed.
- No geographic bus/node coordinates are provided. Some investigators have generated coordinates for graphical display of the feeder layouts, but these are generally not to scale.

These feeders are typically used as the primary circuit backbone for pre-processing scripts (MATLAB or Python) that add additional features to the model before simulation. The additional features include:

- Secondary transformers and service drops at each load point on the primary feeder.
- Different end-use loads and building thermal envelopes.
- Distributed energy resources at different adoption levels.

As designed, these feeders are easy to solve in power flow, unless a pre-processing script creates an overload. They do not require voltage regulators or shunt capacitors, even to serve the designed peak load. These feeders are better suited to support investigation of loads and DER connected at the secondary voltage level, including the meters.

A.4 NREL Large Synthetic Networks

NREL has developed three extremely large-scale hypothetical networks based on geographical regions in North America [4], which are highlighted in Table 10. Each model covers the geographic span of several counties of San Francisco bay, Santa Fe, and Greensboro, providing a data set with size and complexity characteristic of an actual utility system. The models each contain hundreds of distribution substations with thousands of feeders and detailed modeling of high-voltage transmission, medium-voltage distribution, and low-voltage secondary lines. The models also contain accurate models of urban, suburban, and rural areas with both medium-voltage and low-voltage customers.

Table 10: Summary of NREL Large Synthetic Networks

Feeder	Length	Nominal Voltage (kV)	Topology	Service Xfmr	No. of Customers	Peak Load (MW)	N.O. Switches	No. of DERs
Bay Area	79267 km	Multiple	Meshed	Y	5,826 MV 2,194,742 LV		Y	0
Santa Fe Area	945 km MV 982 km LV	Multiple	Meshed	Y	84,154 LV	439 MW	Y	0
Greensboro		Multiple	Meshed	Y	82,110	574 MW	Y	0

Although these feeders provide the most realistic and detailed representation of utility distribution networks, they do not contain any DERs and are far too large for development of advanced power applications and algorithms. Rather, they best serve as a final test for usability and computational scaling prior to use in actual control-room environments.

Appendix B – Modeling Details of the 9500 Node Test System

This section provides detailed documentation of the set of model modifications made to derive the 9500 Node Test System from the original IEEE 8500 Node Test Feeder. The modifications were made in a consecutive, iterative, incremental manner, mimicking the thought process of a utility planning engineer, working systematically to resolve successive requirements, issues, and power flow violations. A conceptual model drawn by the authors to highlight the features of the 9500 Node Test System is shown in Figure 7 below. The subsections below detail the rationale for each set of design changes with snapshots from some of the 33 intermediate models created between the original 8500 Node model and the final 9500 Node Test System. The following subsections follow the requirements outlined above for the feeder to 1) be right-sized, 2) enable reconfiguration, 3) include utility-scale DERs, 4) include customer DERs, 5) support creation of multiple islands, and 6) provide a high level of controllability.

B.1 Derivation from IEEE 8500-Node Test Feeder

Considering the requirements and criteria outlined above, the authors chose to modify the IEEE 8500-node test system instead of developing an entirely new test feeder model. The 8500-node test system was developed ten years ago by R.F. Arritt and R.C. Dugan using an actual utility feeder located in the southeast United States to create a realistic distribution test system [23].

Similar to the other IEEE test feeders, the IEEE 8500 Node Test Feeder is topologically radial, but also includes the secondary center-tapped split-phase 120/240 V transformers and 50ft low voltage

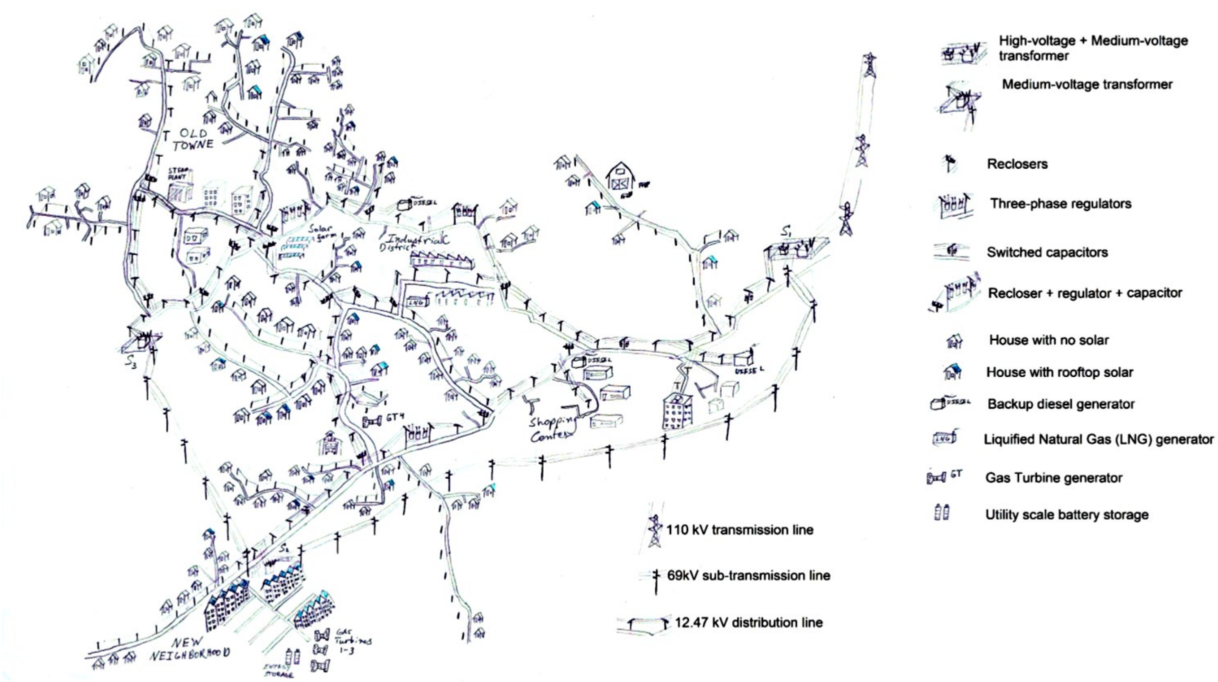

Figure 7: A hand-drawn conceptual model of the 9500 Node Test System used by the authors in developing and adapting the power system model to meet the requirements outlined in Section 4.

secondary lines serving single-phase residential loads. It is a 12.47 kV large radial system with 170 km of overhead lines and underground cables served by a single 115kV substation with a load tap changers (LTC) transformer, three voltage regulators, and four shunt capacitors. The complete details of the original feeder can be found in [23] and [24]. The model was designed to challenge the convergence characteristics of distribution power flow algorithms with a large unbalanced distribution feeder with single-phase loads, LV (secondary) distribution lines, and very long single-phase and three-phase laterals with power flow conditions near the edge of voltage stability limits.

The size, existing features, complexity, and realism of the IEEE 8500 Node Test Feeder served as motivation for adapting the model to represent the anticipated smart distribution grid of the future. Furthermore, the topology and geospatial layout of the 8500 Node Test Model was easily adaptable to define single-phase and three-phase loops, potential microgrids, and separate regions characterized by new or legacy equipment.

B.2 Additional Substations and Sub-transmission Network

The original IEEE 8500 Node Test Case is supplied by an infinite 115 kV source bus, which is maintained at a voltage of 1.05 pu and is connected to a 115-12.47kV step down LTC transformer, which supplies the entire feeder. Under the base-case conditions of the model, the conductor trunk is operating at up to 122% overload between the substation and the first division of the feeder at node `m1142843`, as shown in Table 11 below. To resolve the line overload in the base case (which will be further exacerbated during high load conditions), additional substations or conductor upgrades are necessary. Additional upgrades to VVO equipment settings are also necessary to ensure proper controllability during potential load flow reversals.

Table 11: IEEE 8500 Node Basecase Conductor Overloads

Line	Conductor	Current (Phase A)	Current (Phase B)	Current (Phase C)	Rated Current
`LINE.LN5742828-1`	3-phase ACSR-397	553 A	535 A	525 A	450 A
`LINE.LN5805761-1`	3-phase ACSR-397	524 A	519 A	440 A	450 A

Two additional substations connected by a 69kV network were selected to be placed at the opposite ends of the feeder from the existing substation, as shown in Figure 8. The original source substation, now designated as S1, is divided into three buses at 115kV, 69kV, and 12.47kV, with a 75 MVA delta-wye 115kV/69kV transformer and 20 MVA 69kV/12.47 kV LTC transformer. The intermediate bus is connected to a 69kV sub-transmission line that runs to substations S2 and S3. The other two substations each have a 20 MVA 69kV/12.47kV LTC transformer that connects to the downstream conductor trunk.

High-side and low-side breakers for all substation transformers and line breakers for all 69kV lines are included for realistic modeling of line and transformer protection schemes. However, it was determined that grounding switches on either side of each breaker for possible equipment replacement and maintenance were not needed for the goal of advanced power application development and testing.

B.3 Feeder Conductor Upgrades

The next set of upgrades to model was 1) increasing the size of conductors the lines downstream of the new substations and 2) upgrading multiple single-phase laterals to become alternate 3-ph paths for feeder reconfiguration. As can be seen from Table 12, the original conductors are severely undersized to serve the feeder load in the new configuration. Likewise, the undersized conductors result in severe voltage violations when the feeder load is served only from either of the new substations.

To perform the conductor upgrades, a short software code was written to build a spanning tree between any two nodes and replace the conductor definitions in the original DSS files of the IEEE 8500 node model. This code was run in conjunction with a topology processor that sorted the lines in the original DSS files such that adjacent nodes and lines were listed sequentially in the text file.

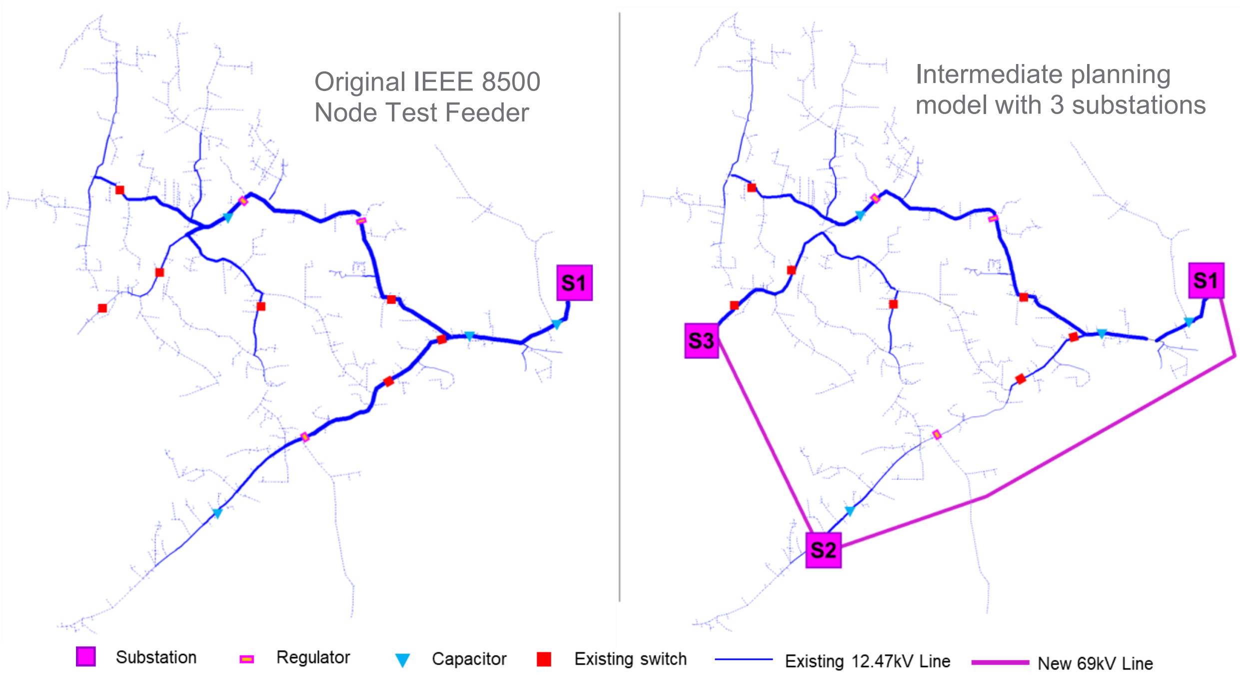

Figure 8: Placement of the new substations and 69kV sub-transmission network overlaid on the original IEEE 8500 Node Test Feeder

Table 12: Sample Line Overloads in Intermediate Three-Substation Model

Line Name	Conductor	Original Model (S1 Only)	All Three Substations	S2 Only	S3 Only	Rating
LINE.LN5742828-1	3-phase ACSR-397	553 A 535 A 525 A	378 A 403 A 382 A	7.3 A 7.3 A 7.3 A	13.4 A 13.4 A 13.4 A	450 A
LINE.LN6379462-2	3-phase ACSR-4	24.1 A 44.4 A 7.1 A	96 A 84 A 105 A	461 A 451 A 481 A	23.4 A 40.4 A 7.3 A	90 A
LINE.LN6044631-1	3-phase ACSR-4	0 A 0 A 0 A	138 A 163 A 141 A	0 A 0 A 0 A	533 A 524 A 528 A	90 A

Additionally, a significant number of single-phase laterals were upgraded to three-phase lines to enable feeder reconfiguration through alternate paths. New three-phase lines were created to connect the new three-phase lines to each other and to the existing three-phase trunks. A summary of the feeder conductor upgrades is presented in Figure 10 below. It is noted that the types of feeder upgrades performed to create the 9500 Node Test System are quite common for utilities across the US, as can be noted by the comparison of historical photos of utility equipment in Figure 9.

Figure 9: Comparison of historical photos of a distribution line running along Reinig Road, Snoqualmie, WA. Between 1990 and 2015, the distribution line was upgraded to a 3-phase line with additional volt-var control equipment.

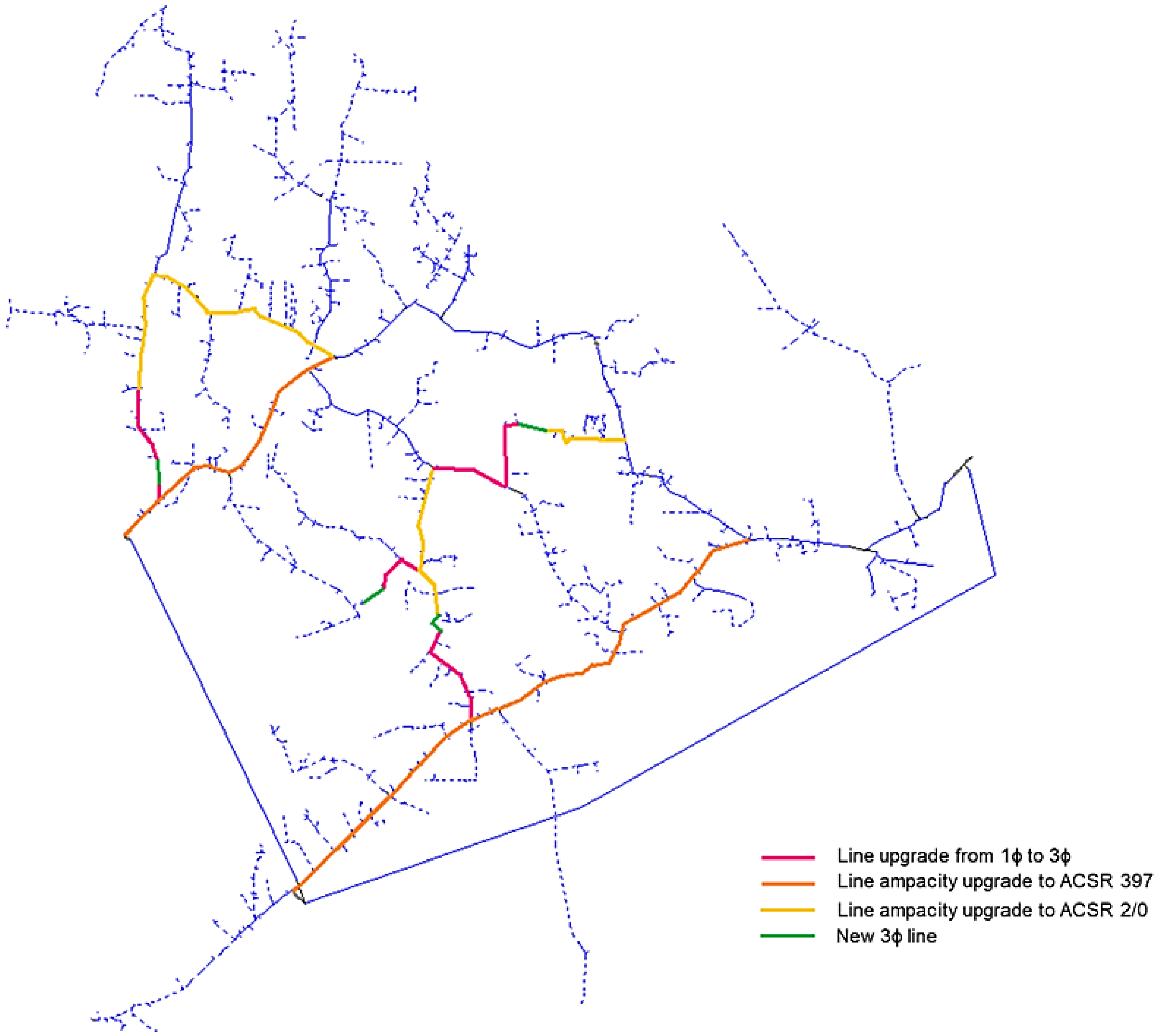

Figure 10: Four types of conductor upgrades were performed to update the IEEE 8500 node model. The location and type of each upgrade is shown in a different color overlaid on the model.

B.4 Reconfiguration and Islanding: Addition of New Neighborhood

To create a realistic model depicting both legacy and future equipment, the concept of a new neighborhood was developed, which would serve as a showcase for smart grid technologies and also be able to operate as an islanded microgrid for extended periods of time without load shedding. The new portion of the feeder includes different topological features than the rest of the model, including

- underground cables for all lines
- load power factor reduced from 0.97 to 0.87, representing more inductive loads
- higher geographic density and larger load consumption, representing the trend towards construction of high-density tract housing, with a total of 1.1 MW additional load
- single point of common coupling (PCC) allowing the entire neighborhood to island from the rest of the feeder during large system disturbances
- ability to perform load-shedding in addition to customer-side demand response on a per-phase basis with single-phase sectionalizers on all laterals
- 100% solar penetration enabling the microgrid to be a net-exporter of energy during certain conditions

To minimize the impact of the neighborhood on power flow studies and advanced power applications on legacy distribution topologies lacking microgrids, the new neighborhood and PCC were placed near substation S2. Thus, large changes in demand and rooftop PV generation would primarily impact the 69kV sub-transmission network. Simultaneously, the location of the microgrid PCC enables studies of reversed power flow, where the microgrid is back-feeding the entire distribution network, simply by isolating the S2 step-down transformer. Figure 11 shows a comparison of the power flow and voltage profile of the feeder with the New Neighborhood supplied by a) substation S2 (with a very short electrical distance to the sub-transmission network) and b) substation S1 (with a very long electrical distance to the sub-transmission network).

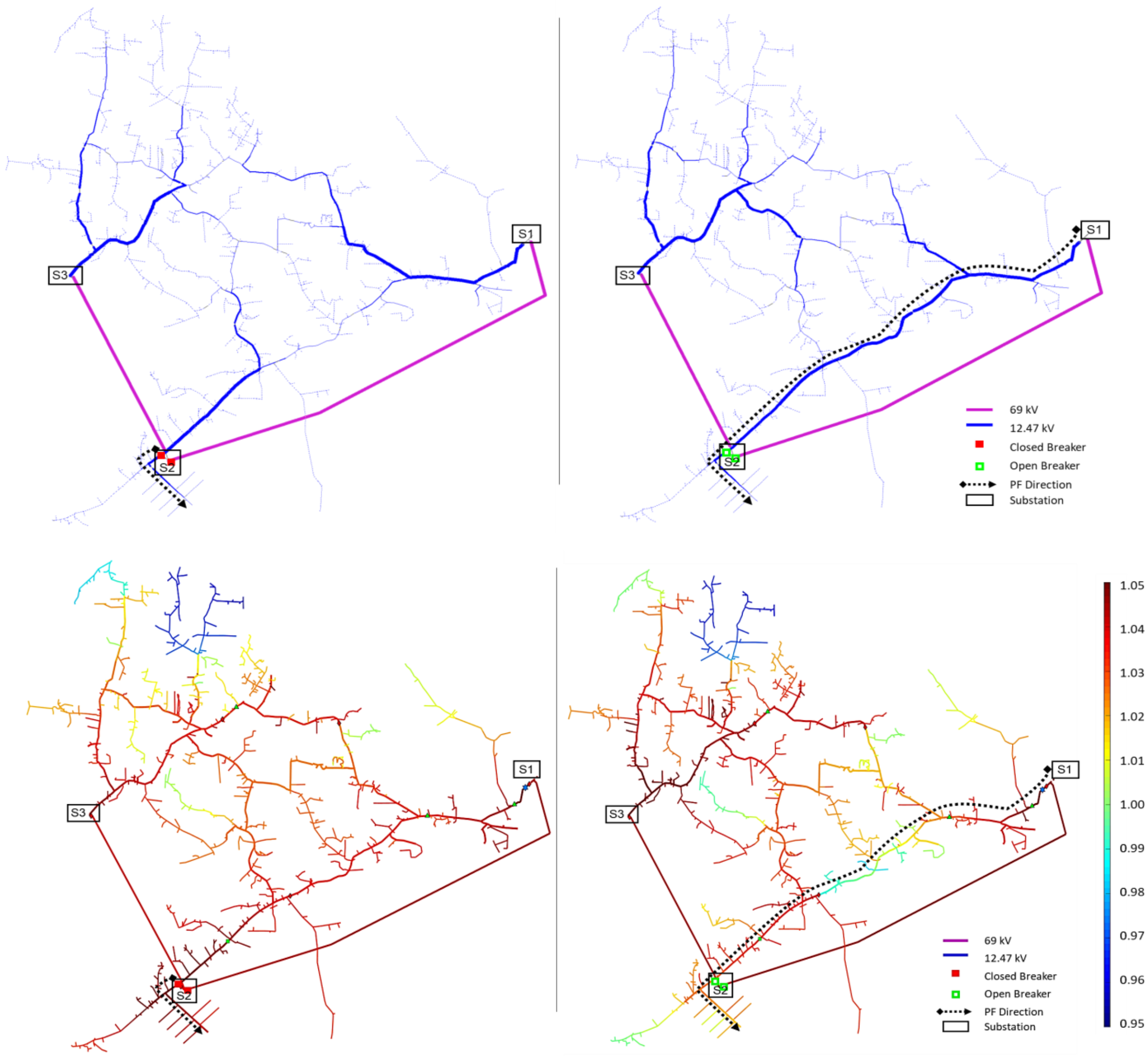

Figure 11: Power flow and voltage plots illustrating how New Neighborhood can be reconfigured. At left, New Neighborhood is supplied by S2, which is very near to the load. At right: The S2 substation transformer is taken out of service and New Neighborhood is supplied by S1, which is very far from the load.

B.5 Reconfiguration: Upgrades to Switching Equipment

The original IEEE 8500 node model contains a limited number of sectionalizers, poletop transformer fuses, and capacitor cutoff switches. However, a significantly greater number of switching devices are needed to enable network reconfiguration, simulation of typical switching actions, and demonstration of the capability of advanced power applications and power flow solvers to transition between meshed and radial topologies

In this discussion, these switches are classified here as normally-open tie switches, and normally closed sectionalizers. Due to software-specific equipment-type definitions, the authors chose not to create specific definitions of whether individual switches were reclosers, air switches, vault-enclosed switches, SCADA-operated sectionalizers, manually-operated sectionalizers, line fuses, or secondary transformer cutout fuses. However, it is anticipated that a general user would be able to infer the type of switch, depending on its location in the model.

Normally open tie-switches were introduced at each of the new three-phase lines and all sections of the feeder that were upgraded from single-phase to three-phase conductor (illustrated previously in Figure 10). An additional set of normally open tie-switches were also added on each of the main conductor trunks between substations S1 and S2 and substations S1 and S3. The new tie-switches are illustrated in green in the Figure 12 below, which also highlights the new sectionalizing switches placed at critical junctions on restoration paths to each section of the feeder, fuses upstream and downstream of regulators, and new substation breakers. The representative smart grid technology regions and load profile neighborhoods are also indicated in the figure.

The new model contains a total of 109 switches and fuses, which can be used to simulate outages of lines, transformers, and regulators, as well as capacitor malfunctions and substation bus faults. The new switches also enable the model transition between several possible radial configurations and an even larger number of mesh topologies. A suggested set of normally-open and normally closed switches to achieve a radial topology is provided in Section 6.

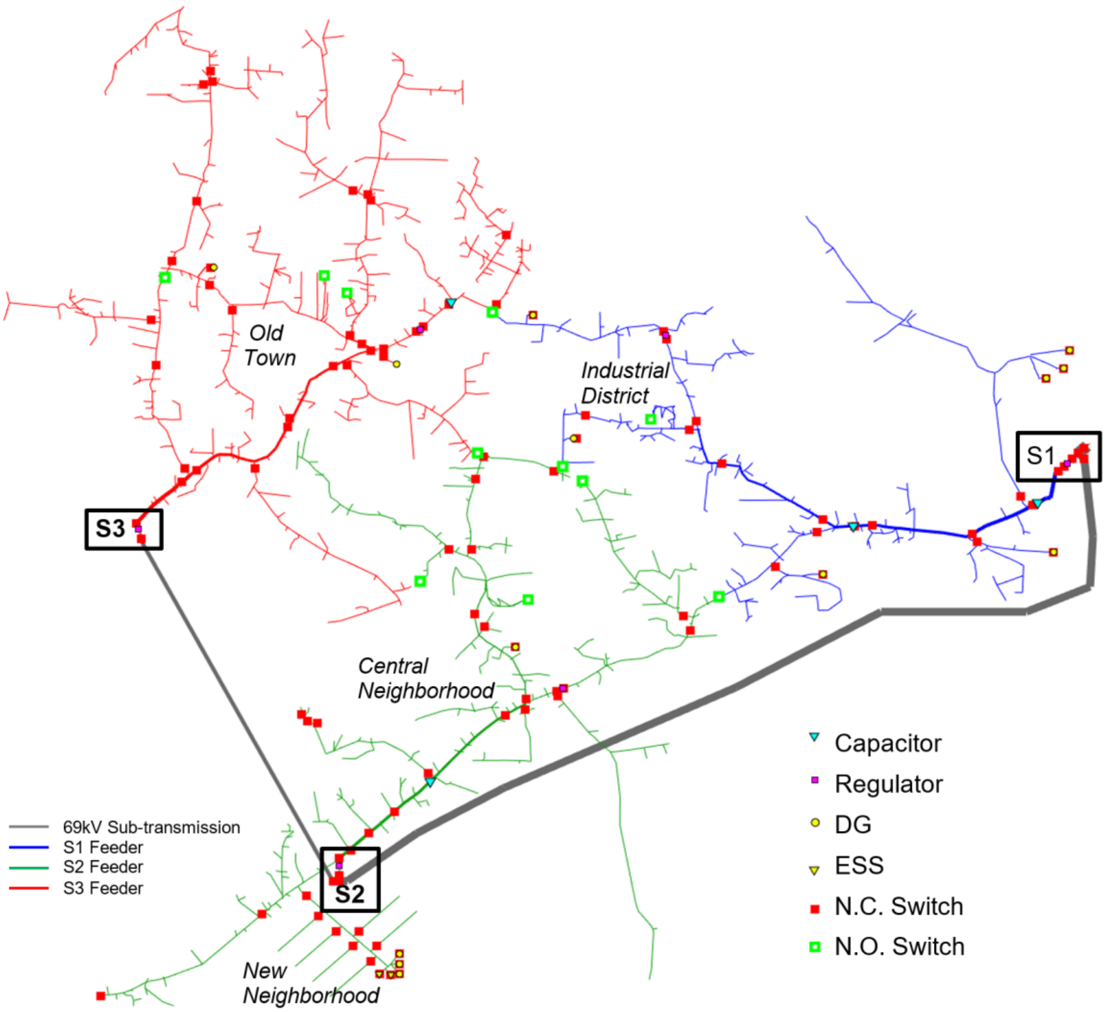

Figure 12: Locations of normally open and normally-closed switches in the 9500 Node Test System, dividing the model into three separate radial sub-feeders. Neighborhoods are in italicized text.

B.6 Utility Scale Distributed Energy Resources

DERs were added to the model to support the high-level goals presented in Section 4, namely improving resilience and reliability, increasing energy efficiency, and enabling multi-point microgrid islanding. To demonstrate the potential uses of DERs in achieving these goals, five categories of representative equipment were added to the model:

- utility-scale community solar
- grid-forming diesel backup generators
- grid-tied microturbines and inverter-connected DGs
- large legacy CHP and new local "peaker" units
- utility-scale energy storage systems

It is common industry practice for some homes, as well as most office parks, industrial buildings, and critical loads to have standalone diesel or propane generators, typically sized between 10kW and 100kW. These generators are nearly always located behind-the-meter, serve a single customer, and are equipped with a transfer switch scheme so that the load is served exclusively by either the utility grid or the backup generator. Such generators are not dispatchable or controllable by a utility; likewise, they are not capable of participating in microgrid operations or serving more than one customer. As a result, such generators are of little interest for the purposes of developing an operations-focused test feeder.

Instead, focus was placed on DER units capable of not only being connected to the distribution grid to increase energy efficiency, but also forming islanded microgrids to improve system reliability and resiliency. Efficient DGs and ESS are capable of providing numerous benefits to the smart distribution grid of the future. During times of peak demand, DERs can alleviate line overloads, reduce locational marginal prices (LMP), improve voltage profiles, reduce losses, and reduce total feeder load (potentially assisting congestion, voltage, and spinning reserve issues in the bulk transmission grid). Likewise, during severe grid disturbance events and natural disasters, dispatchable DERs with frequency regulation capability can form independent islanded microgrids to serve customer load, and potentially even assist in the creation of cranking paths to larger generators during system restoration after a regional blackout.

To maximize the realism and accuracy of the new operations-focused test feeder, the parameters of DERs were based on commercially available DG and ESS systems. A total of 10 DG units were placed throughout the system in alignment with the previously discussed strategy of creating distinct regions of the feeder representing legacy, current, and anticipated smart grid topologies.

The first is the New Neighborhood, which represents the anticipated future distribution grid, with the ability to operate for extended periods of time as an islanded microgrid. To enable this capability, three 200kW CHP microturbines (modeled after the C200S microturbine [30] manufactured by Capstone Turbine Corp) and two 500kWh battery ESS units, which are connected by a pair of 12.47kV – 480V three phase step-down transformers. Each of the DERs is connected to the transformer low-side by a short line and disconnect switch. All of the DERs in New Neighborhood are operating in constant power factor mode, per the requirements of CA Rule 21 [31], [32].

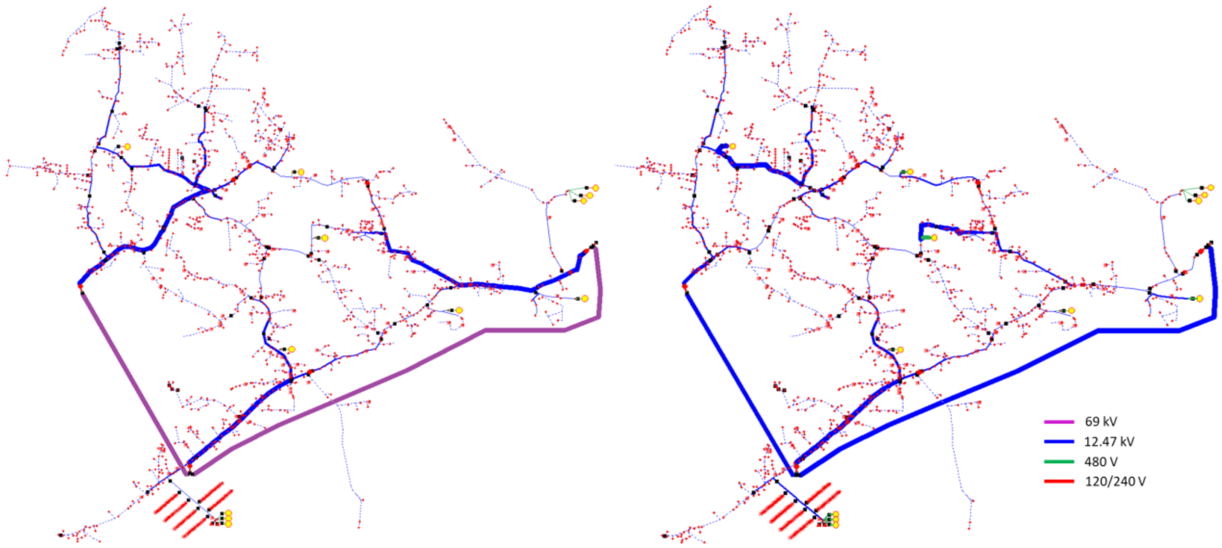

Figure 13: Comparison of power flow of the 9500 Node Test System with all utility-scale DERs off (left) and dispatched at nameplate capacity (right). Notice multiple reversals of power flow direction, including in Old Town, Industrial District, and at substation S1.

The second is Old Town, which includes a 3MW district steam plant providing power and steam heat to neighboring buildings. Representing the configuration of most legacy steam units, the unit is defined as a conventional synchronous generator with a large rotating inertia and operating in PV mode (holding the generation plant high-side bus voltage constant). Nearby is also a 500kW solar farm, which operates under PQ control. Generator step-up transformers are not included for these two DERs since systems of this scale frequently operate at a higher voltage.

Another 200kW microturbine and a large 1800kW LNG reciprocating engine peaker unit (based on the Cummins HSK78G generator [33]) are located in the central portion of the feeder. The LNG unit represents the latest generation of peaker units with electrical efficiencies greater than 40% that can mitigate congestion constraints and very high LMP during peak load conditions. The unit is sized to serve the industrial district and some of the adjacent laterals during islanded operations. Both units are connected through large 12.47kV – 480V three phase step-down transformers. Each of the DERs is connected to the transformer low-side by a short line and disconnect switch.

The final set of DGs represent a relatively new category of generators, which consist of a diesel or LNG reciprocating engine connected through a back-to-back rectifier and inverter [34]. This particular configuration provides a combination of technical and regulatory benefits. The first relates to decoupling the reciprocating engine RPM from grid frequency, enabling the generator speed to follow fluctuations in electrical load. Variation of the generator speed allows the unit to avoid high RPM – low load conditions that result in higher fuel consumption and more frequent maintenance overhauls due to wet-stacking and coking. The second set of benefits derived from inverter-connected DGs relate to utility requirements for DER interconnections. Although specific requirements depend on the individual utility, most require a series of technical studies (including fault current, relaying / protection, synchronization procedures, and power quality) to be completed prior to connection of any synchronous generator. However, inverter-connected DGs are typically classified as smart inverters compliant with CA Rule 21 and IEEE 1547 standards, and can therefore follow expedited approval similar to that for rooftop solar installations.

The 9500 Node Test System includes three inverter-connected generators, including a 620kW diesel unit (based on the Innovus IP CVS 620 generator [35]) in the hospital microgrid, a 100kW LNG unit (based on the InVerde Ultera 125 [36] in the S1 shopping center microgrid, and a 590kW diesel unit (based on the Innovus MVS 600 generator [37]) in the northeast corner of the feeder. All three units are connected through large 12.47kV – 480V three phase step-down transformers. Each of the DERs is connected to the transformer low-side by a short line and disconnect switch. Table 13 below summarizes the capacities of the utility-scale DERs and their locations in the feeder. Figure 12 presents a comparison of the feeder power flow with all DERs off and all DERs dispatched at full capacity.

Table 13: Utility-Scale DER Parameters in the 9500 Node Test System

DER Type	**Name**	**Node**	**Feeder**	**S_{rated} (kVA)**	**P_{rated} (kW)**
Steam plant	`SteamGen1`	`m1026chp-3`	S3	4000	3000
PV	`PVFarm1`	`m1047pv-3`	S3	750	500
Diesel Genset	`Diesel620`	`m1209-dies1`	S1	775	620
LNG Engine Genset	`LNGengine100`	`m1142-lng1`	S1	125	100

Microturbine	`MicroTurb-1,2,3`	`m2001-mt1`
		`m2001-mt2`
		`m2001-mt3`
			S2	250
				250
				250
					200
					200
					200

Wind Turbine	`WindTurb-1,2,3`	`m1186-wt1`
		`m1186-wt2`
		`m1186-wt3`
			S1	50
				50
				50
					75
					75
					75

LNG Engine Generator	`LNGengine1800`	`m1089-lng1`	S1	2250	1800
Diesel Genset	`Diesel590`	`m1089-dies1`	S1	737	590
Microturbine	`MicroTurb-4`	`m1069-mt1`	S2	250	200
Storage	`Storage.Battery1,2`	`m2001-ess1` `m2001-ess2`	S2	250 250	250 250

B.7 Customer (BTM) Rooftop Photovoltaics

A significant amount of customer rooftop photovoltaics is added to the model to represent increasing levels of customer penetration. The level of penetration is varied throughout the model, with rooftop PV present on the residences of 100% customers in New Neighborhood, none in Old Town, and approximately 10% in the remainder of the feeder (with some laterals with a relatively higher level and some with none, reflecting the variation in customer attitudes and homeowner association policies towards rooftop PV). The generation capacity and placement of customers with PV was randomized using a python script.

The configuration by which grid-tied rooftop PV are interconnected is depicted in Figure 14 below. In North America, the vast majority of customers are supplied by 120/240V center-tapped transformers that are connected to a single phase (A, B, or C) and neutral of the medium voltage distribution line. A neutral conductor and two phases, s1 at 120V∠0° and s2 at 120V∠180°, which are run over 50 feet of insulated triplex secondary conductor to the customer meter and main distribution circuit panel. The customer grid-following inverter is connected phase-to-phase from s1 to s2 at 240 volts.

Viewed from the primary feeder side of the transformer, the customers appear as single-phase loads and sources from phase A, B or C to neutral. When modeled on the secondary side of the transformer, these appear as a combination of balanced and unbalanced loads and sources, connected from phases s1 and s2 to neutral. Some of the larger loads are also connected s1 to s2 at 240 volts, and these would appear as balanced if modeled from phases s1 and s2 to neutral. Other loads in the residence, e.g., plug loads and lighting loads, are served at 120 volts, with load connected between s1 (or s2) to neutral, and these can be unbalanced. The unbalanced loads may lead to computational challenges in solving power flow; the voltage drop or rise is likely to be greater than in the balanced case. This degree of unbalance between s1 and s2 is independent of the unbalance that also exists between primary phases A, B and C. For some applications, it is possible to ignore the customer-side phase imbalance and treat the loads as balanced between phases s1 and s2. The split-phase transformer needs to be modeled in detail, including the impedance of secondary circuits.

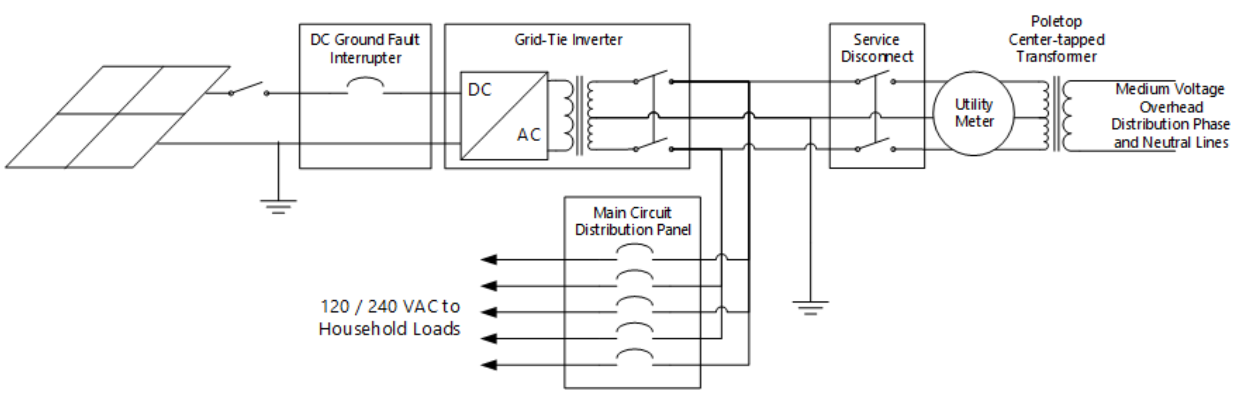

Figure 14: Typical configuration for grid-tied rooftop photovoltaics with two-phase 120/240V connection to the poletop center-tapped transformer

B.8 Controllability and Reconfiguration: Volt-Var Control Equipment

The 9500-Node Test System retains all the original poletop regulators and capacitor banks in addition to the new LTC transformers at new substations S2 and S3. Each of the substation transformers is sized to be able to carry the load of the entire 9500 Node Test System at 75% nameplate rating. Some modifications are made to the control settings of poletop regulators and capacitors to enable reversals of the direction of power flow, which can occur due to switching actions or renewables backfeeding the sub-transmission system. This is done by enabling the reversible property available in most file specification formats. To avoid frequent reversals, the minimum threshold before reversing the regulated node is set at a minimum of 50kW. The parameters of volt-var-control equipment are summarized in Tables 14 through 16.

Table 14: Substation LTC Transformers in the 9500 Node Test System

Name	Substation	Regulated Node	MVA Rating	Reversible?
`Transformer.HVMV69_11Sub1` `Transformer.FEEDER_REG1`	S1	`HVMV11sub3_LSB`	20	No
`Transformer.HVMV69_11Sub2` `Transformer.FEEDER_REG2`	S2	`HVMV11sub3_LSB`	20	No
`Transformer.HVMV69_11Sub3` `Transformer.FEEDER_REG3`	S3	`HVMV11sub3_LSB`	20	No

Table 15: Poletop Regulators in the 9500 Node Test System

Name	Feeder	Regulated Node	MVA Rating	Reversible?
`Transformer.VREG2`	S3	`190-8593`	10	Yes
`Transformer.VREG3`	S1	`190-8581`	10	Yes
`Transformer.VREG4`	S2	`190-7361`	10	Yes

Table 16: Poletop Capacitors in the 9500 Node Test System

Name	Feeder	Node	Type	kVAR
`CapBank1`	S1	`R20185`	1-phase	300 300 300
`CapBank2`	S1	`R42247`	1-phase	300 300 300
`CapBank3`	S3	`R42246`	1-phase	400 400 400
`CapBank4`	S2	`R18242`	3-phase	900

Appendix C – Independent Power Flow Validation Results

To promote broader adoption of the 9500 Node Test System, the model has been prepared in multiple file formats for not only specific software, but also generic model importers, with both CSV and CIM XML files. To validate the model, the power flow for the recommended base case is solved with both OpenDSS and GridLab-D. A set of six sample points (Table 17), including four that were used in [23] for validation for validation of the original IEEE 8500 Node Test Feeder were selected for the power flow validation, and presented graphically in Figure 15.

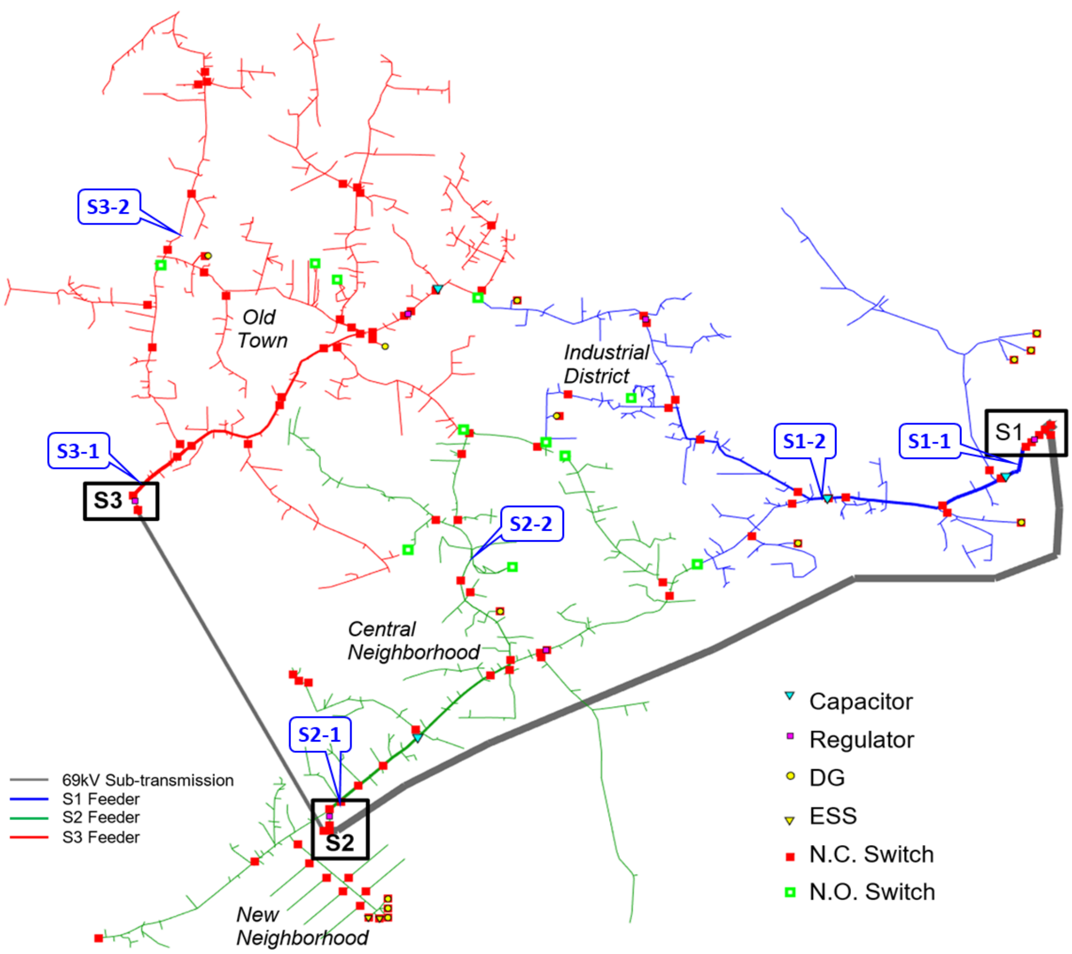

Figure 15: Locations of the sample points used for validation of power flow results. Points S1-1, S1-2, S2-1, and S3-2 were also used by [23] for validation of the original IEEE 8500 model.

Table 17: Sample Points used for Power Flow Validation of the 9500 Node Test System

Sample Point	Node	Line	Feeder	Comments
S1-1	`E192860`	`Line.ln5815900-1`	S1	Also used for original 8500 node model validation by RC Dugan
S2-1	`M1047303`	`Line.ln6380847-1`	S2	Also used for original 8500 node model validation by RC Dugan
S3-1	`E203026`	`Line.ln6044631-1`	S3	New point at S3 LSB
S1-2	`L2955077`	`Line.ln6381853-1`	S1	Also used for original 8500 node model validation by RC Dugan
S2-2	`M1069310`	`Line.ln5486729-1`	S2	New point in middle of S2 feeder
S3-2	`M1026907`	`Line.ln6350537-1`	S3	Also used for original 8500 node model validation by RC Dugan

The model files were derived from the EPRI OpenDSS files for the IEEE 8500 Node Test Feeder. These source files are included in the folder "Original DSS Models" in CIMHub [38] and contain extensive inline documentation of new features and model upgrades. These source files were converted to CIM XML using the CIM100 command of the cimext branch of OpenDSSCMD 1.2.17.

Two independent power flow solutions were generated. The first independent solution was created by an EPRI team led by Davis Montenegro-Martinez, which used OpenDSS to solve both the original model files and a model version derived from the official CIM XML model using the CIMHub software package. The second independent solution was created by a PNNL team lead by Jing Xie, which used GridLAB-D to solve a model version derived from the CIM XML using the CIMHub software package. The raw power flow results files from each group are included in the "Power Flow Results" folder. The results are combined and compared in Tables 18 through 23 below.

Some differences exist in the way OpenDSS and GridLab-D model split-phase customer transformers and distributed energy resources. The 9500 Node Test System contains a very high penetration of DERs, with 12 distributed generators with 7060 kW of nameplate capacity, 3 centralized PV/battery units with 1500 kW of nameplate capacity, and 177 rooftop PV inverters with 2444 kW of nameplate capacity. With a total of 11 MW of available DERs, any minor differences in modeling of SynchronousMachine or PowerElectronicsConnection objects between particular solvers are greatly amplified by the high DER penetration of the 9500 Node Test System. None of the previous IEEE Test Feeders had any significant amount of DER penetration

Table 18: Power Flow Validation for Sample Point 1

Solution	Phase	VLN (volt)	V angle (rad)	Phase Current (amp)	Current angle (rad)	P (kW)	Q (kVar)	S (kVA)	Comparison	Volt % Diff	kVA % Diff
Developer OpenDSS	A	7365.16	-0.5533	139.57	-0.5545	1028.0	1.3	1028.0	Dev vs EPRI	0.003%	0.001%
EPRI Original DSS	A	7364.95	-0.5534	139.58	-0.5545	1028.0	1.1	1028.0	Dev vs PNNL	0.010%	0.190%
EPRI Conv. OpenDSS	A	7361.27	-0.5531	139.67	-0.5546	1028.1	1.5	1028.1	PNNL vs EPRI	0.013%	0.191%
PNNL GridLab-D	A	7365.91	-0.5533	139.29	-0.5612	1026.0	8.1	1026.0			
Developer OpenDSS	B	7362.61	-2.6477	133.74	-2.6300	984.5	-17.4	984.7	Dev vs EPRI	0.003%	0.001%
EPRI Original DSS	B	7362.40	-2.6481	133.75	-2.6300	984.5	-17.8	984.7	Dev vs PNNL	0.003%	0.678%
EPRI Conv. OpenDSS	B	7359.87	-2.6475	133.82	-2.6298	984.7	-17.5	984.9	PNNL vs EPRI	0.005%	0.684%
PNNL GridLab-D	B	7362.80	3.6353	132.83	3.6428	978.0	-7.4	978.0			
Developer OpenDSS	C	7356.88	1.5394	161.37	1.5003	1186.3	46.4	1187.2	Dev vs EPRI	0.003%	0.002%
EPRI Original DSS	C	7356.68	1.5398	161.38	1.5003	1186.3	46.9	1187.2	Dev vs PNNL	0.001%	0.127%
EPRI Conv. OpenDSS	C	7354.41	1.5402	161.46	1.5004	1186.5	47.2	1187.4	PNNL vs EPRI	0.002%	0.125%
PNNL GridLab-D	C	7356.82	1.5399	161.58	1.4921	1187.3	56.8	1188.7			

Table 19: Power Flow Validation for Sample Point 2

Solution	Phase	VLN (volt)	V angle (rad)	Phase Current (amp)	Current angle (rad)	P (kW)	Q (kVar)	S (kVA)	Comparison	Volt % Diff	kVA % Diff
Developer OpenDSS	A	7346.40	-0.5603	124.08	-0.5109	910.4	-45.0	911.5	Dev vs EPRI	0.004%	0.002%
EPRI Original DSS	A	7346.08	-0.5601	124.08	-0.5110	910.4	-44.8	911.5	Dev vs PNNL	0.020%	0.483%
EPRI Conv. OpenDSS	A	7340.78	-0.5595	122.31	-0.5057	896.6	-48.3	897.9	PNNL vs EPRI	0.015%	0.483%
PNNL GridLab-D	A	7344.95	-0.5599	123.50	-0.5188	906.4	-37.3	907.1			
Developer OpenDSS	B	7348.26	-2.6581	125.55	-2.6091	921.5	-45.2	922.6	Dev vs EPRI	0.004%	0.003%
EPRI Original DSS	B	7347.94	-2.6587	125.56	-2.6091	921.5	-45.7	922.6	Dev vs PNNL	0.034%	0.096%
EPRI Conv. OpenDSS	B	7345.70	-2.6577	123.88	-2.6040	908.7	-48.8	910.0	PNNL vs EPRI	0.030%	0.094%
PNNL GridLab-D	B	7345.74	3.6246	125.71	3.6657	922.7	-38.0	923.4			
Developer OpenDSS	C	7367.59	1.5376	123.31	1.5638	908.2	-23.8	908.5	Dev vs EPRI	0.004%	0.008%
EPRI Original DSS	C	7367.28	1.5370	123.33	1.5637	908.3	-24.3	908.6	Dev vs PNNL	0.034%	0.201%
EPRI Conv. OpenDSS	C	7365.45	1.5381	117.03	1.5831	861.1	-38.8	862.0	PNNL vs EPRI	0.029%	0.193%
PNNL GridLab-D	C	7365.11	1.5371	123.60	1.5544	910.2	-15.7	910.4			

Table 20: Power Flow Validation for Sample Point 3

Solution	Phase	VLN (volt)	V angle (rad)	Phase Current (amp)	Current angle (rad)	P (kW)	Q (kVar)	S (kVA)	Comparison	Volt % Diff	kVA % Diff
Developer OpenDSS	A	7364.65	-0.5603	171.17	-0.9287	1176.0	454.0	1260.6	Dev vs EPRI	0.010%	0.153%
EPRI Original DSS	A	7363.88	-0.5609	171.45	-0.9321	1176.5	458.0	1262.5	Dev vs PNNL	0.039%	0.550%
EPRI Conv. OpenDSS	A	7350.34	-0.5601	174.19	-1.0031	1156.8	548.9	1280.4	PNNL vs EPRI	0.029%	0.395%
PNNL GridLab-D	A	7361.77	-0.5608	172.18	-0.9374	1178.7	466.2	1267.5			
Developer OpenDSS	B	7416.52	-2.6581	180.46	-3.0252	1249.2	480.3	1338.4	Dev vs EPRI	0.010%	0.144%
EPRI Original DSS	B	7415.76	-2.6588	180.73	-3.0284	1249.8	484.1	1340.3	Dev vs PNNL	0.061%	0.902%
EPRI Conv. OpenDSS	B	7408.20	-2.6568	174.71	-3.0978	1170.4	552.5	1294.3	PNNL vs EPRI	0.051%	0.751%
PNNL GridLab-D	B	7412.00	3.6244	182.19	3.2468	1255.3	497.9	1350.4			
Developer OpenDSS	C	7400.47	1.5376	143.53	1.1757	993.4	376.2	1062.2	Dev vs EPRI	0.010%	0.175%
EPRI Original DSS	C	7399.73	1.5373	143.80	1.1716	993.7	380.5	1064.1	Dev vs PNNL	0.065%	0.630%
EPRI Conv. OpenDSS	C	7387.91	1.5382	147.30	1.0998	985.3	461.9	1088.2	PNNL vs EPRI	0.055%	0.452%
PNNL GridLab-D	C	7395.65	1.5375	144.53	1.1531	990.9	400.8	1068.9			

Table 21: Power Flow Validation for Sample Point 4

Solution	Phase	VLN (volt)	V angle (rad)	Phase Current (amp)	Current angle (rad)	P (kW)	Q (kVar)	S (kVA)	Comparison	Volt % Diff	kVA % Diff
Developer OpenDSS	A	7309.56	-0.5707	84.52	-0.8629	591.6	177.9	617.8	Dev vs EPRI	0.021%	0.026%
EPRI Original DSS	A	7311.13	-0.5706	84.52	-0.8628	591.7	178.1	617.9	Dev vs PNNL	0.001%	0.050%
EPRI Conv. OpenDSS	A	7306.55	-0.5703	84.58	-0.8626	591.8	178.1	618.0	PNNL vs EPRI	0.020%	0.024%
PNNL GridLab-D	A	7309.64	-0.5706	84.56	-0.8718	590.2	183.4	618.1			
Developer OpenDSS	B	7306.59	-2.6651	91.88	-2.9398	646.2	182.1	671.3	Dev vs EPRI	0.024%	0.027%
EPRI Original DSS	B	7308.31	-2.6644	91.89	-2.9398	646.2	182.7	671.5	Dev vs PNNL	0.028%	0.344%
EPRI Conv. OpenDSS	B	7304.96	-2.6638	91.94	-2.9393	646.3	182.7	671.6	PNNL vs EPRI	0.051%	0.373%
PNNL GridLab-D	B	7304.55	3.6190	91.59	3.3282	641.0	191.8	669.0			
Developer OpenDSS	C	7313.37	1.5219	89.23	1.2369	626.3	183.5	652.6	Dev vs EPRI	0.015%	0.020%
EPRI Original DSS	C	7314.49	1.5226	89.23	1.2369	626.2	184.0	652.7	Dev vs PNNL	0.032%	0.048%
EPRI Conv. OpenDSS	C	7311.32	1.5229	89.28	1.2372	626.3	184.0	652.8	PNNL vs EPRI	0.047%	0.067%
PNNL GridLab-D	C	7311.03	1.5224	89.22	1.2298	624.5	188.1	652.3			

Table 22: Power Flow Validation for Sample Point 5

Solution	Phase	VLN (volt)	V angle (rad)	Phase Current (amp)	Current angle (rad)	P (kW)	Q (kVar)	S (kVA)	Comparison	Volt % Diff	kVA % Diff
Developer OpenDSS	A	7242.56	-0.5742	48.34	-0.8533	336.5	96.4	350.1	Dev vs EPRI	0.004%	0.002%
EPRI Original DSS	A	7242.25	-0.5751	48.34	-0.8533	336.6	96.2	350.1	Dev vs PNNL	0.040%	1.084%
EPRI Conv. OpenDSS	A	7232.78	-0.5742	48.41	-0.8525	336.6	96.2	350.1	PNNL vs EPRI	0.036%	1.094%
PNNL GridLab-D	A	7239.65	-0.5745	47.83	-0.8690	331.4	100.5	346.3			
Developer OpenDSS	B	7226.34	-2.6756	64.63	-2.9482	449.8	125.8	467.0	Dev vs EPRI	0.005%	0.003%
EPRI Original DSS	B	7226.00	-2.6759	64.64	-2.9482	449.8	125.6	467.1	Dev vs PNNL	0.091%	0.528%
EPRI Conv. OpenDSS	B	7225.18	-2.6752	64.65	-2.9475	449.9	125.6	467.1	PNNL vs EPRI	0.087%	0.522%
PNNL GridLab-D	B	7219.75	3.6075	65.03	3.3281	451.3	129.5	469.5			
Developer OpenDSS	C	7291.40	1.5202	25.42	1.2268	177.4	53.6	185.3	Dev vs EPRI	0.005%	0.007%
EPRI Original DSS	C	7291.07	1.5201	25.42	1.2269	177.4	53.6	185.3	Dev vs PNNL	0.065%	0.519%
EPRI Conv. OpenDSS	C	7294.80	1.5225	25.41	1.2292	177.4	53.6	185.3	PNNL vs EPRI	0.061%	0.509%
PNNL GridLab-D	C	7286.65	1.5202	25.57	1.2124	177.5	56.4	186.3			

Table 23: Power Flow Validation for Sample Point 6

Solution	Phase	VLN (volt)	V angle (rad)	Phase Current (amp)	Current angle (rad)	P (kW)	Q (kVar)	S (kVA)	Comparison	Volt % Diff	kVA % Diff
Developer OpenDSS	A	7117.29	-0.5672	33.55	-0.8278	230.7	61.5	238.8	Dev vs EPRI	0.010%	0.055%
EPRI Original DSS	A	7118.00	-0.5669	33.57	-0.8276	230.9	61.6	238.9	Dev vs PNNL	0.097%	0.296%
EPRI Conv. OpenDSS	A	7093.48	-0.5656	33.62	-0.8261	230.4	61.4	238.5	PNNL vs EPRI	0.107%	0.241%
PNNL GridLab-D	A	7110.42	-0.5670	33.68	-0.8329	231.1	62.9	239.5			
Developer OpenDSS	B	7212.58	-2.6704	31.37	-2.9288	218.7	57.8	226.3	Dev vs EPRI	0.000%	0.041%
EPRI Original DSS	B	7212.56	-2.6700	31.38	-2.9286	218.8	57.9	226.3	Dev vs PNNL	0.120%	0.393%
EPRI Conv. OpenDSS	B	7202.56	-2.6638	31.43	-2.9224	218.8	57.9	226.4	PNNL vs EPRI	0.120%	0.350%
PNNL GridLab-D	B	7203.90	3.6134	31.53	3.3480	219.2	59.6	227.1			
Developer OpenDSS	C	7248.31	1.5324	25.43	1.2725	178.1	47.4	184.3	Dev vs EPRI	0.007%	0.036%
EPRI Original DSS	C	7247.82	1.5322	25.44	1.2727	178.2	47.3	184.4	Dev vs PNNL	0.164%	0.535%
EPRI Conv. OpenDSS	C	7210.59	1.5340	25.58	1.2745	178.2	47.3	184.4	PNNL vs EPRI	0.158%	0.496%
PNNL GridLab-D	C	7236.40	1.5328	25.60	1.2658	178.7	48.9	185.3			

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