Distribution Feeder Modeling for Time-Series Simulation of Voltage Management Strategies

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***Abstract*— This paper presents techniques to create baseline distribution models using a utility feeder from Hawai'ian Electric Company. It describes the software-to-software conversion, steady-state and time-series validations of a utility feeder model. It also presents a methodology to add secondary low-voltage circuit models to accurately capture the voltage at the customer meter level. This enables preparing models to perform studies that simulate how customer-sited resources integrate into legacy utility distribution system operations.**

***Index Terms*—Distribution networks, Integrated circuit modeling, Time-series simulation, Voltage control, Volt-VAR.**

I. INTRODUCTION

Utilities and technology developers are increasingly interested in understanding the impacts of distributed technology and customer-sited resources on distribution feeder operations. To simulate how distributed technology such volt-VAR devices or photovoltaic (PV) inverters with grid support functions (GSF) integrates into legacy utility voltage management schemes, it is very important to create models of the utility distribution system that accurately represent the present field operations. This paper describes some techniques to prepare and validate real utility distribution feeder models for quasi-static time-series (QSTS) power flow simulation. The baseline QSTS models can then be modified to create scenarios that can be compared to current utility operations.

It is increasingly important to represent as accurately as possible the voltage ranges that are measured at customer locations because utilities are modifying existing distributed energy resources (DER) interconnection standards to enable DERs to regulate voltage. The present U.S. interconnection standard, IEEE 1547-2003 [1], prohibits DERs from actively regulating voltage. Exceptions to the standard can be made with the agreement of the utility and the PV owner, but such exceptions are rare. However, the ballot draft revision to IEEE 1547 will also require DERs to be capable of the GSFs [2]. In recognition of the fact that DER-based voltage support is needed at higher penetration levels, both California and Hawai'i have published interconnection rules requiring various GSFs starting in September 2017. In response to these changes, Underwriters Laboratories (UL) published UL 1741 Supplement SA (UL 1741 SA) procedures to validate inverter behavior for volt-VAR, volt-watt, and constant power factor among other grid support functions. To better understand how customer-sited resources will impact utility operations, creating good baseline models of the current utility operations to compare with future scenarios is an important step in research studies.

Previous studies that looked at customer-sited resources with GSFs created time-series models of real utility feeders [3-6]. However, the load and PV systems in those models were represented at the aggregate level at the primary of the service transformers, or secondary circuit approximation was a star network design, which is often far from the field design.

This paper presents techniques to create baseline models using a utility feeder from Hawai'ian Electric Company. These techniques were used in [7] to determine the effectiveness of various GSFs at regulating voltage and quantifying annual energy curtailment to solar PV customers. The rest of this paper is organized as follows: Section II describes the software-to-software conversion and steady-state validation of a utility feeder model; Section III describes a methodology to add secondary low-voltage circuit models to the utility feeder model; Section IV presents data processing techniques to create time-series data of customer load and PV profiles; Section V presents the time-series validation of the model; and, Section VI concludes.

II. MODEL CONVERSION AND STEADY-STATE VALIDATION

Recently, utility companies across the U.S. made considerable effort toward improving the way they represent distribution systems, and have sizeable portions of their distribution feeders represented in commercial software environments. However, these environments have a paying license fee, and do not have DERs—particularly, inverter based PV-powered—modeled to the level of detail necessary to conduct research studies. For this reason, the GIS-based feeder model from the distribution modeling software that the Hawai'ian Electric Companies use is converted to the open-source distribution modeling software, OpenDSS [7] that is used in this paper for simulation voltage regulation operating strategies with PV inverters providing GSF. To validate this

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software-to-software conversion, the steady-state (one time-step) power flow solutions with planning loads from the commercial software environment and OpenDSS are compared. This paper does not commercialize the OpenDSS software nor does it support its exclusive use for such studies; rather, the authors present it as one of the freely available software options for conducting such distribution studies.

The example utility distribution feeder in this study, denoted "feeder L", is converted from the commercial distribution software to OpenDSS. This conversion uses an automated Python® script developed at the National Renewable Energy Laboratory (NREL) that uses network configuration (.xml) and line configuration (.txt) as inputs. To use the tool, the feeder model provided by Hawai'ian Electric in Microsoft Access® database format was opened in the commercial distribution software and then exported in Extensible Markup Language (XML) format. Additionally, the line impedance information also was extracted from the commercial distribution software and used as an input by the tool. The conversion tool takes the two files described (i.e., the feeder in .xml format and the line construction report in .txt format) as inputs and creates a folder with the OpenDSS files. Then, the user can open the master circuit file and run it in OpenDSS.

The steady-state verification of the OpenDSS model was performed based on the following metrics: 1) the similarity in feeder topology between the converted model to the original model (based on visual inspection); and, 2) the difference between the node voltages and sequence impedance values for the converted model and the original model (less than 5%). The steady-state validation is performed by solving a power flow with the given planning load from the commercial distribution software calculated via load allocation from supervisory control and data acquisition (SCADA) data measured at the substation.

Fig. 1 shows the topology of the feeders from the commercial distribution software and the converted model in OpenDSS. From Fig. 1 we can observe that the line distances and coordinates are appropriately converted. The subsequent step for verification compares the voltages and sequence impedances obtained from OpenDSS with those obtained from the commercial distribution software. Fig. 2 presents the voltage comparison, along with the errors, and Fig. 3 presents the sequence impedance and comparison errors for feeder L. The maximum error in voltage comparisons between the commercial distribution software and OpenDSS is 0.5% for feeder L. The maximum error in sequence impedance comparison between the commercial distribution software and OpenDSS is 2%. Although the maximum error is 2%, relatively few occurrences of errors are greater than 1%, as shown in the histograms in Fig. 3.

III. DESIGN OF SECONDARY CIRCUITS

Recently, utility companies represent distribution feeders in commercially available distribution software tools to conduct planning studies. To the best knowledge of the authors, however, there is no utility that has accurate or realistic representations or models of the low-voltage secondary networks. It is critical to add this level of detail to more accurately capture not only the annual voltages at the primary medium-voltage level, but also at the secondary low-voltage level to which PV systems are connected and required to meet tariff requirements.

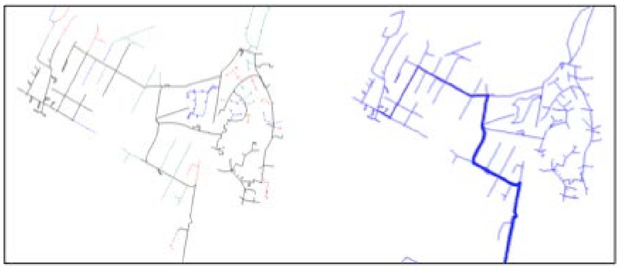

Figure 1. Geographical view of L distribution feeder in the commercial distribution software on the left and OpenDSS on the right.

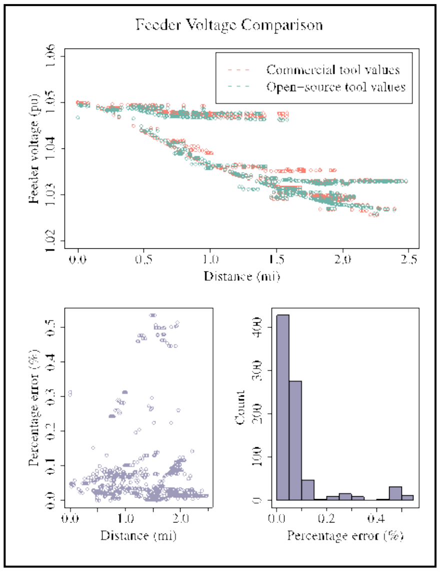

Figure 2. Percentage error of voltage with respect to distance from the feeder head for feeder L

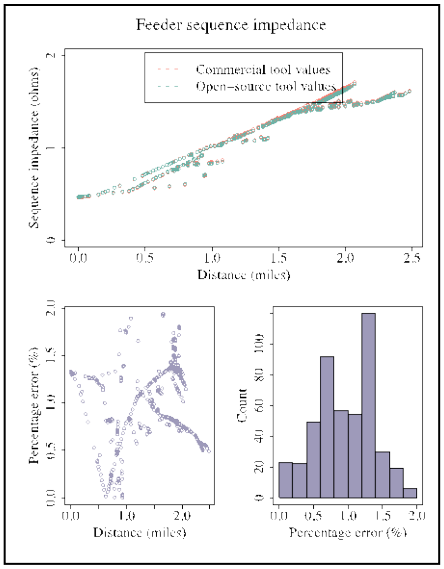

Figure 3. Percentage error of sequence impedance values with respect to distance from the feeder head for feeder L

To add accurate representations of secondary circuits, the aggregate load nodes (or service transformer nodes) in feeder L are classified into customer types to design secondary circuits based on this customer classification. This is followed by automating the building of such circuits in OpenDSS. The goal is to add more detail to the medium-voltage distribution models—including service transformers and secondary circuits in the OpenDSS model as shown in Fig. 4 —to capture the voltage drop that occurs from the medium-voltage bus to the customer residence, where the PV system inverters are connected. Ultimately, accurate simulations of the voltage at the terminals of the residential inverters are desired. Most of the advance inverter modes are control functions that depend on the local voltage sensed by the inverter, and thus emphasize the importance of capturing the voltage drops in secondary circuits.

To classify load nodes into customer types, the coordinates of each load node were superimposed on the land-use type. The GIS department at NREL performed this task. The customer types are selected based on the GIS classification and the availability of secondary designs. Hawai'ian Electric provided 55 detailed designs for adding low-voltage circuits to the existing model. The Hawai'ian Electric team was consulted to determine that the commercial and multifamily aggregated load nodes will be kept at the primary level in the model, because there is no significant voltage drop expected at those customer locations with typically oversized secondary circuits. For the overhead rural customers, the following secondary build-out assumptions were considered: (1) customers are 200 ft. apart from each other; (2) overhead #2 cable size is used for secondary lines; and, (3) there are six customers per shared secondary circuit.

This is followed by building the secondary circuits for underground (UG) and overhead (OH) residential customer types according to the flowchart diagram in Fig. 5. The methodology is based on matching the service transformer size and the number of customers per transformer to the pool of secondaries and the real values from the field. The process is automated in Python® to create the OpenDSS files of all secondary service transformers, lines, and each load representing a house and existing customer PV systems.

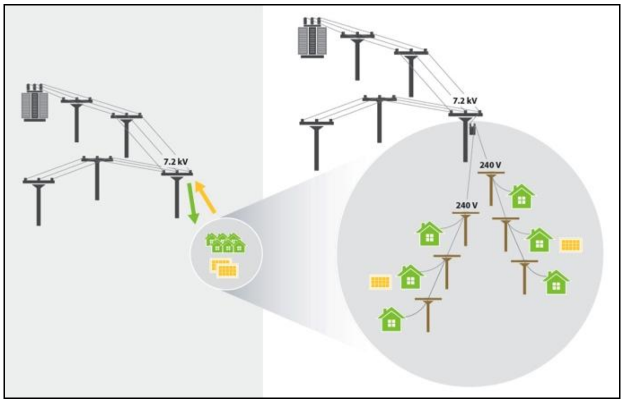

Figure 4. Diagram showing the load and solar model provided by the utility on the left, and the detailed load transformer and secondary circuit added to the existing model for every load node.

TABLE I. SECONDARY CIRCUIT DESIGNS FOR EACH CUSTOMER TYPE

Customer Type	**Description of Secondary Designs (x Number of Designs)**
M3 UG Residential	Housing developer detailed drawings (x 30)
M4 UG Residential	Housing developer detailed drawings (x 11)
Feeder L UG Residential	Companies secondary upgrade designs (x 3)
OH Residential	Companies secondary upgrade designs (x 11)
OH Rural	NREL proposed design

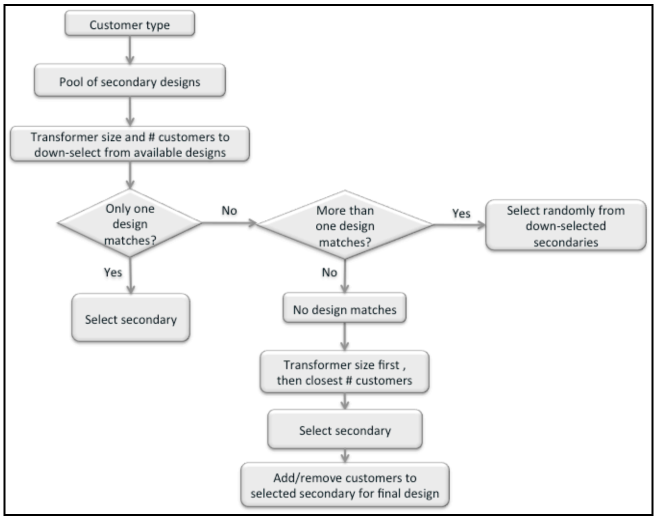

Figure 5. Flowchart showing the methodology to assign a secondary design process to OH and UG residential customers from a total of 55 detailed secondary designs provided by the utility.

IV. DATA PROCESSING FOR TIME-SERIES SIMULATION

A critical step in this effort is the synthesis of the data that will derive the time-series model. The data obtained from the utility for this process is: 1) substation SCADA voltage, current, and real and reactive powers for 2015; 2) individual feeder SCADA voltage, current, and real and reactive powers as available for 2015; 3) megawatt-hours/megawatt PV power production for two PV regions of interest on O'ahu, 4) 15-minute irradiance profiles for the two PV regions of interest on O'ahu, and 5) 15-minute data on kilowatt-hour and voltage from the customer meter through Advanced Metering Infrastructure (AMI).

1) *Replacing Missing and Outlier Data:* The first step in the data-processing task is to identify missing and outlier data and replace it. An example of outlier data is a reconfiguration event in which a feeder picked up loads from a circuit in another substation, which is shown by abnormally high loading. Due to the good correlation of circuits within a substation, circuit data due to load transfer events were replaced with the adjacent circuit data connected to the same substation. For missing data (when there were overall SCADA outages) the data was replaced with the most appropriate adjacent (in time and day of week) time series data.

2) *Estimating Customer Loads:* The following section describes the estimation of the gross load (also sometimes referred to as “native” load)—i.e., the load profile if there was no PV system installed in the feeders. During nighttime hours, the gross load and the measured SCADA data net load are the same. During daytime hours, however, the objective is to determine the shape of the demand without PV production. This gross-load profile can be used for estimating unknown load profiles among customers. Two methods are explored for this purpose: 1) real to reactive power regression method (PQ regression); and, 2) MWh/MW method.

The real to reactive power linear regression at night is used to determine the real power during daytime hours. This PQ regression method only works for circuits that serve residential customers predominantly with invariable power factor during nighttime hours. This assumption also works only if the existing solar PV systems are connected at unity power factor. The advantages of using the PQ regression method are that it relies on power measurements, and it is independent of estimating how much PV energy is in the system and its profile.

The other method explored for estimating gross load is to estimate the PV production for each of the feeders and subtract that from the SCADA net load at each time step. For this, the utility provided MWh/MW values versus irradiance of a fleet of systems in the feeder L region. The MWh/MW values account for the orientation and losses of PV systems. Fig. 6 shows the AM and PM values highlighted in red and blue, respectively. The degree 3 polynomial fit of the distribution of all of the values is described in (1).

$$y = 3.293e^{-10}x^3 – 7.418e^{-7}x^2 + 1.243e^{-3}x^2 \qquad (1)$$

The polynomial MWh/MW curve multiplied by the total installed PV systems rating (MW) for each circuit gives an estimate of the PV production at every given time step. Note that the MWh/MW curve was provided at an hourly resolution, and the SCADA net load is processed at 15-minute time steps. Because the utility also provided typical 15-minute plane of array (POA) irradiance curve for the geographical region of interest, an estimated final MWh/MW 15-minute curve using the irradiance profile is found.

The PQ regression method could not be used on feeder L due to the presence of large inductive loads during daytime hours, making the PQ regression method invalid because it is based on nighttime real and reactive power correlation. Thus, feeder L circuit required the use of the MWh/MW method. Feeder L had approximately 1 MW of peak load (corresponding to 85 aggregate load nodes in the distribution model) that is not metered through AMI for which the substation load profile shown in Fig. 7 using the MWh/MW method was used.

For the time-series simulation, the available AMI customer data was used to derive the load profiles of individual customers. For the customers that are not in the AMI program, the substation load multiplier as shown in Fig. 7 is used to derive the non-AMI loads.

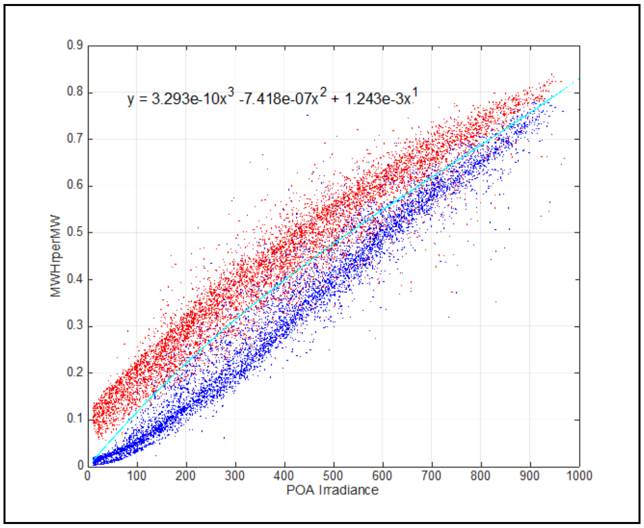

Figure 6. MWh/MW values versus irradiance for a fleet of PV systems in the M34 region. Note that the AM and PM values are in red and blue colors, respectively.

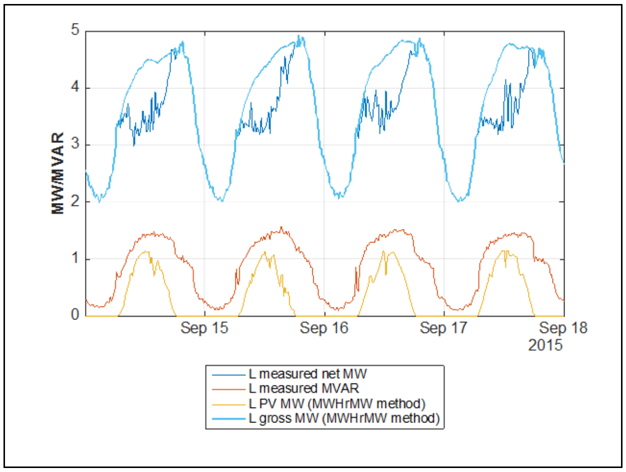

Figure 7. The L feeder gross real power from the MWh/MW method and PV system profiles

V. TIME-SERIES VALIDATION RESULTS

The results of deriving the OpenDSS time-series model with the multipliers are shown in Fig. 8 at the secondary of a service transformer. These are compared to the real power and voltage data measurements provided by the utility. When comparing voltages at the measurement location, the voltage profile of the OpenDSS model matches the field data. Note that the legacy Load Tap Changer (LTC) in the model is behaving akin to its field performance, as observed by the step changes and voltage profiles driven by the LTC regulation in both field and modeled voltages.

Fig. 9 shows the voltage envelope comparison plots between the simulated and measured AMI voltage data for a service transformer location. The exact representation of secondary distribution circuits in the model and exact locations of the AMI meters were not available; rather, only which service transformer the AMI meters are connected to was known. So, the comparison is of the envelope (maximum and minimum) of the simulated and the measured customer voltage data connected to the same transformer. The maximum and minimum demonstrate how well estimated the voltage is at the beginning and at the end, respectively, of a secondary circuit.

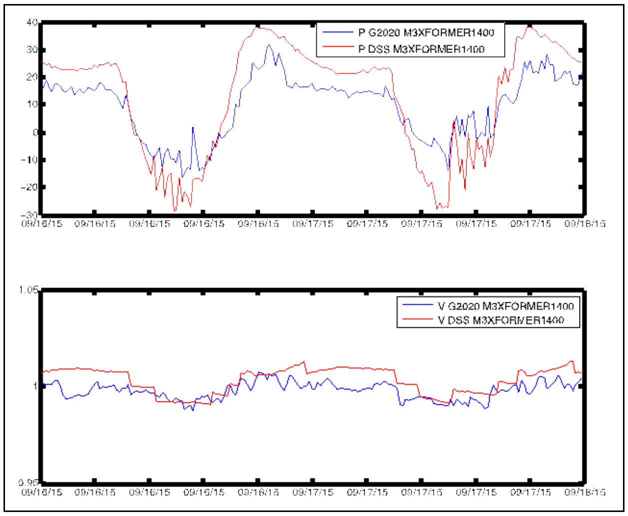

Figure 8. Power (top) and voltage (bottom) time-series comparison between Grid 20/20 measurements and OpenDSS model at M3 transformer 1400 for September 16–17, 2015

Fig. 10 shows the voltage to distance from the substation plot for feeder L; primary voltages are relatively flat, and the bulk of the voltage drop or rise occurs in the service transformer and secondary circuits. This demonstrates the importance of the effort to approximate secondary circuits as accurately as possible to capture the local voltage that will be used for voltage based control functions at customer-sited resources such as advanced PV inverters.

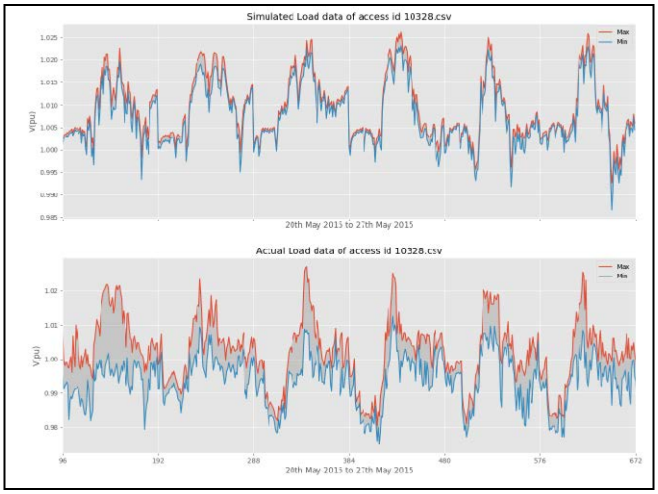

Figure 9. Envelope of maximum and minimum voltage across the secondary circuit of a service transformer location in which maximum and minimum simulated (top) and measured (bottom) voltage envelops.

VI. CONCLUSIONS

This paper presents techniques to create baseline models using a utility feeder from Hawai'ian Electric Company. It describes a software-to-software conversion and steady-state validation results of a utility feeder model and presents a methodology to add secondary low-voltage circuit models to the utility feeder model. The utility circuit is then validated with time-series measurements and the results show the importance of approximating secondary low-voltage circuits to accurately capture voltage at the customer meter level. Creating and validating baseline models of the current utility operations is important to compare with future scenarios in which customer sited resources are integrated in the operation of distribution systems.

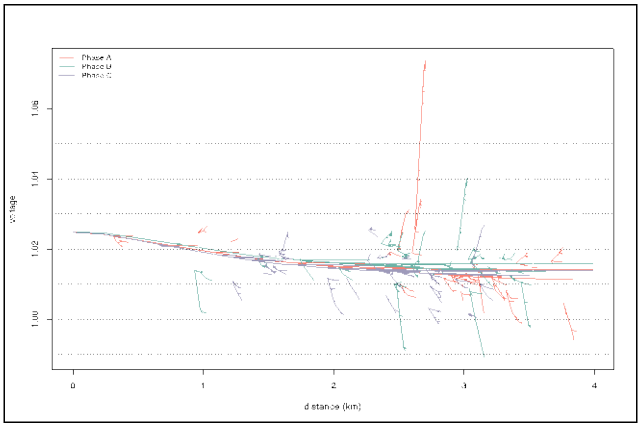

Figure 10. Voltage to distance from the substation plot of primary voltages (solid lines) and secondary voltages (dotted lines) for feeder L on May 23 at 12:30 p.m.

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