AN ANALYSIS OF DISTRIBUTED PHOTOVOLTAICS ON SINGLE-PHASE LATERALS OF DISTRIBUTION SYSTEMS

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Submitted to the Graduate Faculty of

The Swanson School of Engineering in partial fulfillment

of the requirements for the degree of

Master of Science

University of Pittsburgh

2015

UNIVERSITY OF PITTSBURGH

SWANSON SCHOOL OF ENGINEERING

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Andrew P Reiman, M.S.

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The adoption of distributed photovoltaic systems promises to benefit society by reducing pollution and dependence on finite natural resources. When deployed carefully, distributed photovoltaic systems have the potential to provide economic benefits to both the end-user and the system operator. However, high levels of photovoltaics and arbitrary end-user-driven deployment can introduce negative impacts to distribution systems including voltage rise, load imbalance, harmonics and system protection concerns.

Power distribution systems have a natural capability to accommodate a limited amount of distributed generation with only minimal impacts on the system. Some system operators allow distributed generation up to 15% of the peak load level (equivalent to a conservative estimate of the minimum load) of a segment of the circuit without a detailed study. With increasing interest in distributed photovoltaic generation in some regions, demand for distributed generation regularly exceeds the 15% per segment threshold. The results of distributed generation studies on a circuit segment typically cannot be applied to another segment, even if the two segments are part of the same distribution feeder.

Single-phase laterals pose additional challenges to the deployment of distributed generation. Their topology can lead naturally to load imbalance. Imbalance can be exacerbated by the introduction of high levels of photovoltaics. In addition, single-phase laterals are often

protected by a fuse. Excessive distributed generation on a fused single-phase lateral can cause undesired fuse behavior for faults both within and adjacent to the lateral.

This thesis examines the limits of photovoltaics on single-phase laterals of distribution systems. Factors which limit photovoltaic levels including voltage rise, load balance, harmonics, and system protection concerns are examined. Conservative limits, which can be used as guidelines for photovoltaic systems on single-phase laterals are discussed and expanded. Strategies to mitigate negative impacts of PV and increase potential deployments levels are examined and discussed. Finally, tools that have been developed for a research project with FirstEnergy to automate distribution system modeling and analysis are discussed. Hypothetical case studies of new PV systems on single-phase laterals of existing distribution systems are performed.

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ACRONYMS AND DEFINITIONS

The following acronyms are used throughout this document.

DG: Distributed Generation

GIS: Geographic Information System

PV: Photovoltaic (system or panel)

The following definitions are used throughout this document.

Customer: An individual metered load on a distribution system; often the paying customer of a utility that owns the distribution system.

Distribution Primary: The medium-voltage portion of a distribution system between the substation and the distribution transformers. Some distribution systems have more than one primary voltage level.

Distribution Secondary: A portion of a feeder between a distribution transformer and one or more customers.

Distribution Substation: Modeled as a load on the transmission system or a source on the distribution system, distribution Substations contain substation transformers, line tap changers, and other system protection and control devices and can supply one or more feeders.

Distribution Transformer: A transformer that converts a medium-voltage distribution primary to a low-voltage distribution secondary.

Feeder: A portion of a distribution system with a single point of connection to a distribution substation and connections to several customer loads.

High-Voltage: Transmission or subtransmission system voltage; greater than 35 kilovolts.

Lateral: A radial branch of a feeder.

Low-Voltage: Distribution secondary voltage; less than 1000 volts.

Line Tap Changer (LTC): An auto-transformer with an adjustable winding used as a regulation device at a distribution substation or elsewhere on a distribution system.

Medium-Voltage: Distribution primary voltage; between 1 and 35 kilovolts.

Penetration: A measure of the (photovoltaic or other) distributed generation on a segment. Penetration can be expressed as the percentage of generation capacity over maximum load.

Radial System: A nodal network in which each node has exactly one pathway to an origin node.

Segment: An interconnected portion of distribution system with clear boundaries such as a feeder, lateral or secondary.

Substation Transformer: A transformer that converts a transmission or subtransmission high-voltage to a medium-voltage distribution primary.

Triplex: An interwoven three-conductor cable often used to supply distribution secondaries.

ACKNOWLEDGMENTS

Thanks to FirstEnergy for financial support for researching power distribution systems and for permission to use FirstEnergy system data in this thesis. Thanks to Tim Croushore, Justin Price, Dean Philips, Mark Josef, Eva Gardow, Joe Waligorski of FirstEnergy the technical support on this thesis and other research endeavors. Additional thanks to National Grid and Babak Enayati for permission to use National Grid system data in this thesis and for coauthoring my first technical publication. Special thanks to Dr. Tom McDermott, Dr. Gregory Reed, Dr. Alexis Kwasinski, and Dr. William Stanchina for serving as committee members and for the technical, intellectual, and professional guidance during my graduate studies at the University of Pittsburgh.

1.0 INTRODUCTION

Photovoltaic systems installed on residential and commercial properties (distributed photovoltaic systems) provide an opportunity to improve the sustainability of the electric power systems of developed countries. Economic incentives have caused an increased level of adoption of photovoltaic systems in some regions. Existing power systems were not designed to support high levels of distributed generation, instead relying on the economics of bulk generation. Introducing distributed generation, including photovoltaic systems, to existing power systems can cause complications including voltage rise, load imbalance, harmonics, and protection concerns. Early studies identified that for a particular region of Oklahoma, existing infrastructure could support a PV penetration of approximately 15% of peak load in each segment of the circuit [1]. The definition of a circuit segment can be ambiguous. A feeder on a distribution system can be a convenient segment to analyze but it might mask localized issues on the feeder. Restricting the distributed generation behind each meter to the same penetration level as the entire feeder is probably unnecessarily restrictive. In this thesis, single-phase laterals of distribution systems and distribution secondaries are each analyzed for limits on photovoltaic penetration. Suggested limits are developed and discussed.

This introduction section first includes a high-level overview of power systems. Single-phase laterals of distribution systems and distribution secondaries are characterized. Next, an overview of distributed generation and specifically, distributed photovoltaic systems is included.

In section 2, factors that limit the deployment potential of photovoltaic systems are examined. In section 3, case studies of photovoltaic systems on single-phase laterals of distribution systems and on distribution secondaries are examined.

1.1 THE GRID: POWER SYSTEMS

Power systems were originally designed primarily to deliver power from large, efficient, power plants to various customers. Distributed generation, particularly on relatively isolated areas such as single-phase laterals of distribution systems and distribution secondaries, presents challenges that power systems were not always designed to handle. This section describes the high-level structure of power systems and characterizes single-phase laterals and distribution secondaries.

1.1.1 Generation, Transmission, and Distribution

Power systems are the world's largest machines. They are designed to connect power sources to power loads. Generally, it is most efficient to produce power in bulk at large power plants such as hydroelectric, coal, nuclear and natural gas plants. Three-phase power is carried along power transmission systems from such bulk generation sites to load centers at high voltages. At substations near load centers, power is stepped down to medium voltages and connected to individual loads by power distribution systems. Figure 1 shows the basic layout of a traditional power system consisting of generation, transmission, and distribution.

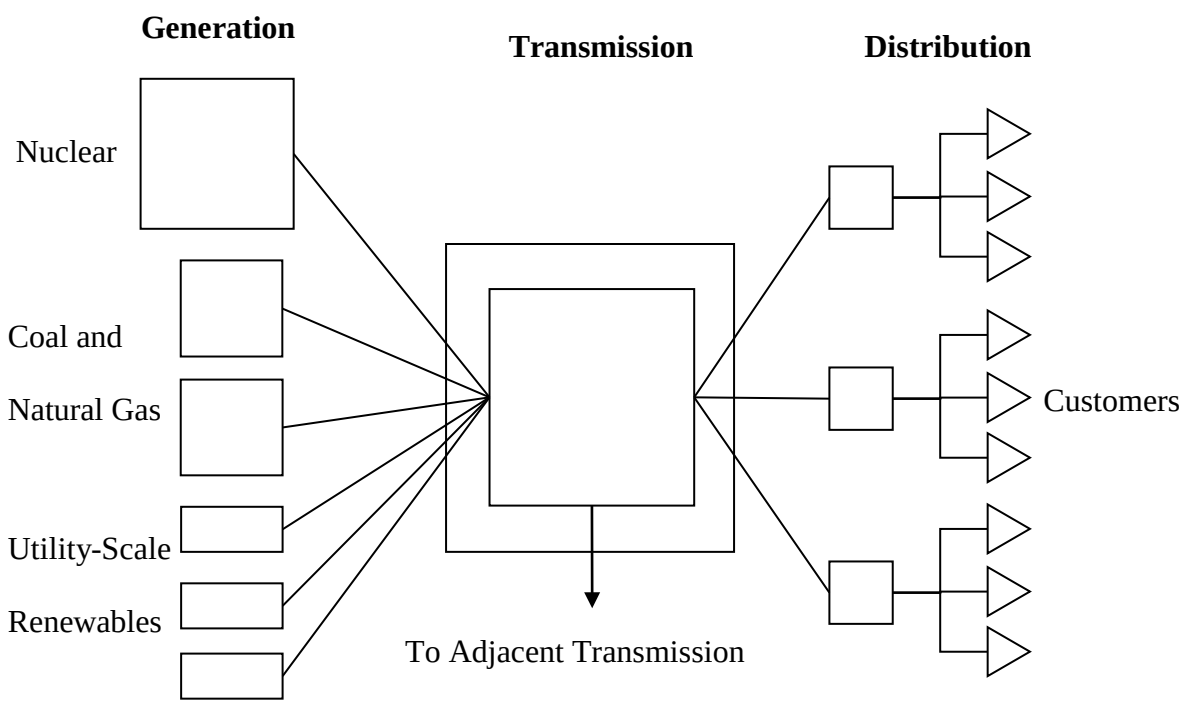

Figure 1. Traditional Power System

The majority of power is generated in bulk at large power plants sized from natural gas power plants rated on the order of hundreds of megawatts to large nuclear power plants rated up to more than one gigawatt per reactor. The largest power plants produce power by isolating mechanical energy and converting it into electrical energy using rotating machinery: a prime mover or turbine that is directly coupled to the power system. The physical rotation frequency of the prime mover is proportionate to the electric frequency of the power system.

In hydroelectric plants, moving water is used to physically turn turbines. In coal and nuclear plants, heat is produced by combusting coal and by nuclear fusion, respectively; the heat is used to generate steam, which is used to turn steam turbines. In natural gas plants, gas is combusted to turn a turbine directly; in combined cycle plants, heat from this combustion is also used to turn a steam turbine. Large wind plants can be coupled to the power system in multiply

ways, including synchronously and through power electronics. Large solar plants interface with the power system using power electronics and are therefore not directly coupled to the power system; however, these plants also produce bulk power.

Large power plants of all kinds are typically located away from large population centers where load exists. A power transmission system moves power from generators towards loads. Transmission systems are meshed like a grid. There is more than one way for power to flow from one point to another. The result is that many interconnected generators serve power to multiple discrete loads. The generators are electrically synchronized at the system frequency. Transmission systems are typically designed robustly such that if one or more line and/or generator is out of service, sufficient power will still be delivered to all loads. Between each generator and the transmission system, the voltage is stepped up to a high voltage (on the order of hundreds of kilovolts).

For power flowing on a conductor between two points, conductor losses are lower for higher voltages. This makes it desirable for transmission over large distances. However, higher voltage also requires larger physical clearances from conductor to conductor and from each conductor to the ground as well as physically larger equipment. Because of these constraints, high voltage is rarely delivered directly to customers. Instead, the voltage is stepped down at least once before it reaches the customer.

At distribution substations, voltage is stepped down to medium voltage. Distribution substations are supplied either directly by the transmission system or by a subtransmission system, operating at an intermediate voltage level. Each distribution substation can be viewed as an aggregate load on the transmission or subtransmission system.

1.1.2 Distribution Systems

Distribution systems carry power from distribution substations to individual customers. Distribution substations contain one or more distribution transformers, which step the transmission or subtransmission voltage down to the distribution voltage. Most of the length of a distribution system operates at medium voltage. Some large customers are connected directly to the medium voltage system; however, the majority of customers, especially residential customers, connect to a low-voltage (less than 1-kV) secondary. The low-voltage is provided by a distribution transformer, which steps medium voltage primary down to the low voltage secondary.

Some distribution systems, especially in large cities, are tightly meshed. Tightly meshed distribution systems have a topology with multiple paths from most or all points at the medium voltage level back to the transmission or subtransmission system. However; most distribution systems in North America have either a lightly meshed topology with a limited number of paths from a given point at the medium voltage level to the transmission or subtransmission system or radial with exactly one path from any point at the medium voltage level to the transmission or subtransmission system. The radial system topology can be compared to a tree with branches.

Some distribution substations, especially those that serve lightly meshed or radial systems, contain one or more distribution transformers with secondaries supplying one or more feeders. A feeder is a portion of a distribution system with a single point of connection to a distribution substation under normal operation. A typical North American feeder supplies a peak load on the order of a few to several megawatts.

Each feeder is typically fed through a line tap changer or voltage regulator, an autotransformer (non-isolating transformer) which maintains the voltage at the feeder head

within a relatively small bandwidth in an attempt to ensure that the voltage throughout the feeder is within specified tolerances (often between 0.95 per-unit and 1.05 per-unit). In some cases, additional voltage regulation measures are required to comply with ANSI standards. Options include using additional distributed line tap changers throughout the feeder and installing shunt capacitors, which provide reactive power support to inductive distribution systems and cause the local voltage to rise.

To provide the most reliable service to the most customers, system protection measures are implemented to clear faults and/or isolate damaged sections of the system. Distribution system protection schemes usually consist of switching devices, which open either temporarily or permanently when an unsafe condition is detected. Reclosers can be opened temporarily and reclosed one or more times in an attempt to clear a fault. Finally, fuses melt automatically in the presence of a sustained fault, isolating a section of the feeder until the fuse is replaced. Sectionalizers automatically isolate circuit segments by counting pulses of fault current, in situations where there is either too much or too little fault current for a fuse to work.

Power flow through radial distribution feeders can be simulated using computer models. The transmission system can be modeled as an ideal three-phase source with a Thevenin equivalent impedance. The impedances of each conductor and transformer in the distribution system can be input to the model, then the Thevenin equivalent impedance from each point or node in the distribution system can be computed. Information about loads can be supplied, then the current through each conductor and the voltage at each node can be computed. If a distribution system model is built using known system information, changes to the system can be simulated to anticipate the behavior of the real system.

1.1.3 Single-Phase Laterals

Distribution feeders typically receive reasonably well balanced three-phase power from transmission systems. Many customers, especially in residential areas, receive single-phase power. Three-phase systems operate most efficiently when power flow is balanced evenly among the three phases. To achieve ideal efficiency, each three-phase point, or node, of a distribution system would have the same voltage magnitude among the phases, and each three-phase component (transformer and conductor) would carry the same current magnitude among the three phases.

For some sections of distribution systems, it is most cost-effective to supply groups of physically adjacent single-phase customers with the same single-phase lateral branch off of the three-phase main line (single-phase lateral). Ideally, a combination of single-phase laterals would still balance the three-phase nodes of the distribution system. Figure 2 shows a single-phase lateral branching from a three-phase main line.

Figure 2. Single-Phase Lateral Branching from Three-Phase Main Line

Single-phase laterals are typically characterized by a radial topology and a single connection point to the larger distribution system. This means that, similar to a radial distribution system, a single-phase lateral can be modeled as an ideal source behind an equivalent impedance. If the entire distribution system is radial, the equivalent impedance at the beginning of the lateral will be the sum of the equivalent impedance of the distribution system and the impedance of all components (transformers and conductors) between the head of the feeder and the head of the lateral.

The connection point between a single-phase lateral and the larger distribution system is often a single fuse. The fuse serves to protect the rest of the distribution system in the event of a fault on the lateral. In general, all of the current from a fault on a fused lateral would be supplied through the fuse, causing the fuse to melt and the fault to clear. Figure 3 shows a fuse on a distribution system.

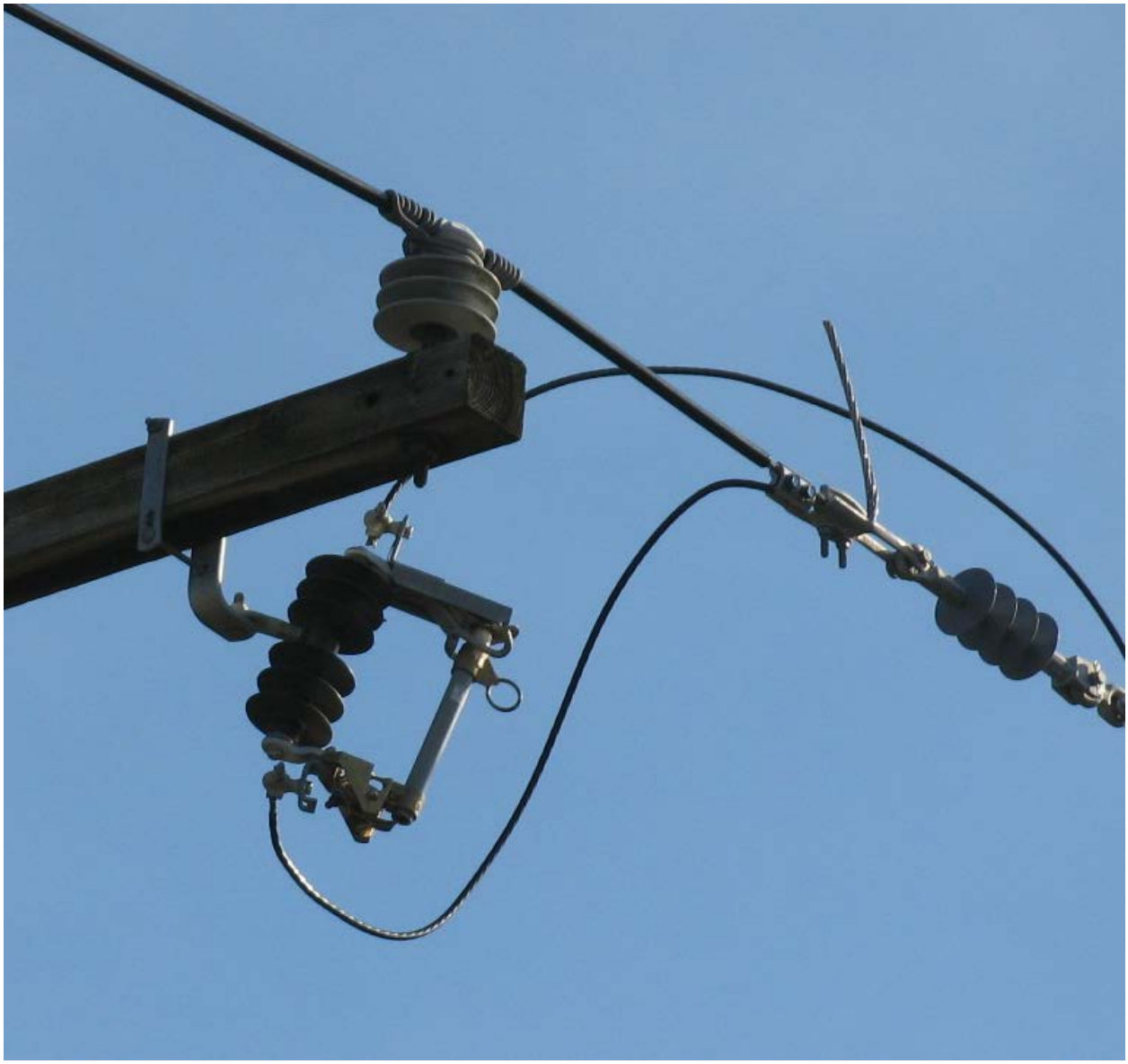

Figure 3. Medium Voltage Fuse on a Distribution System

1.1.4 Distribution Secondaries

Before power is supplied to most customers, especially residential customers and especially on single-phase laterals, a distribution transformer steps the voltage from a medium voltage to a low voltage. The portion of a distribution system on the low voltage side of a distribution transformer is referred to as a distribution secondary. A distribution secondary can supply one or more individual customers, depending on the size and the physical distance between customers. Figure 4 shows a distribution transformer supplying a split-phase secondary.

Figure 4. Split-Phase Secondary Fed from Single-Phase Lateral Primary

In North America, residential customers are typically supplied 240-V/120-V split-phase power. This split-phase configuration is a three wire single-phase power system with a line-to-line voltage of 240-V and a line-to-neutral voltage of 120-V. The two phases have a 180° nominal phase angle differential; meaning that in a balanced system, the instantaneous voltage of one phase is always -1 times the instantaneous voltage of the other phase.

Distribution transformers that supply split-phase power have one single-phase primary coil and two secondary coils, each producing 120-V. The negative terminal of one secondary coil and the positive terminal of the other secondary coil are connected at a common point and a three-conductor line carries power to individual customers.

North American residential customers typically have relatively large appliance loads connected across the 240-V terminals a split-phase secondary. Many smaller loads are connected somewhat arbitrarily across one of the individual split phases. Electrical code attempts to achieve a reasonable balance between phases.

1.2 DISTRIBUTED GENERATION

While the majority of the power in a traditional power system is generated at large power plants, power can also be generated on a smaller scale to supply localized loads more directly. Distributed generation refers to power generation units that are connected directly to a power distribution system. Common examples of distributed generation include backup generators at facilities such as hospitals and residential photovoltaics. Interest in distributed generation, including distributed photovoltaics, has been increasing recently for a variety of reasons.

1.2.1 Distributed Generation in General

Distributed generation is often owned by a customer rather than the power system operator. Customers that own some types of distributed generation generators can improve their power availability by switching to backup generation when the larger power system is unavailable. Some customers choose to install renewable distributed generation like wind turbines or photovoltaics to reduce their consumption of carbon-based electricity. Interconnection between the distributed generation and the grid is specified in IEEE Std. 1547 [2].

From the perspective of the power system operator, distributed generation owned by a customer either reduces the effective load of the customer by supplying a portion of that load directly or supplies power back to the grid. Active distributed generation reduces the power supplied by the substation.

Distributed generation is usually intended to supply local real power. Some types of distributed generators are coupled to the system frequency like smaller versions of large power plants. These generators naturally supply local reactive power as well as local real power to the system. Distributed generators that are connected to the distribution system using power electronics may default to supplying only real power to the system. However, power electronics based systems can be configured to supply or absorb reactive power while supplying real power.

Mathematically, distributed generation can be modeled as a negative load. Distributed generation can be factored in to the power flow simulations discussed in Section 1.1.2. In general, distributed generation will cause less current to flow from substations to loads and usually results in a higher local voltage. Distributed generators will also supply current to local faults. In general, special planning may be required in order to support distributed generation.

1.2.2 Distributed Photovoltaics

Distributed photovoltaic systems are a type of distributed generation that is of special interest to power system operators. Photovoltaic modules, also known as solar panels, convert energy from the sun into electric energy. A modular design allows photovoltaic systems to scale efficiently down to sizes appropriate for distributed generation. For example, a residential system sized on the order of a few kilowatts can fit on the roof of a home. Such a system costs a few thousand dollars [3] and is rated to produce 80% of rated output after 25 years [4]. Additional government incentives and favorable pricing schemes in some states make PV systems even more economical. Some homeowners also prefer to produce electricity on their own property and/or prefer to consume electric power produced from renewable sources.

Photovoltaic systems produce power proportionate to the instantaneous solar irradiance. This means that their peak possible power occurs daily at solar noon; however, the actual power production is affected by the weather. Annual solar production tends to be highest during summer months, which corresponds to the highest load months in many residential circuits corresponding with high usage levels of air conditioners. In general, peak solar power production corresponds roughly with high power system load. This allows an opportunity to alleviate system stress by reducing the peak load.

In general, residential electric utility bills incentivize owners of distributed photovoltaic systems maximize the real power output of their generators. This can easily be achieved by operating with a unity power factor and neglecting reactive power. In some cases this is not ideal from a power system perspective, where it might be preferable to take advantage of the local voltage regulation capabilities of the power electronics of photovoltaic systems.

Shadows cast by clouds overhead can cause changes in power production that are faster than normal changes in the aggregate load shape of a circuit segment. One way to limit the impact of these fluctuations is to limit the worst-case voltage rise caused by the PV system. Other options include using power electronics or distributed storage to regulate the voltage.

1.3 LIMITS ON DISTRIBUTED PHOTOVOLTAICS

An analysis of high levels of PV on distribution systems [5, 6] demonstrated that voltage rise and current capacity of conductors limited distributed generation under different conditions. In [5], a simplified radial feeder was modeled with an aggregate load connected to an ideal source at the substation by 4/0 aluminum conductors modeled with ideal resistance. In [6], Monte Carlo methods were used to examine general trends of overvoltage and overcurrent PV deployment limits using 336 PV deployment scenarios across 16 distribution feeders. In a more detailed study of distributed generation from rotating machinery on single-phase laterals [7], four factors were found to constrain deployment: (1) system voltage impacts, (2) fuse timing, (3) fault detection sensitivity, and (4) harmonic voltage distortion introduced by the DG. A typical 12.47-kV rural feeder was modeled in detail and voltage rise was found to be the limiting factor on deployment to rural feeders in general.

The two analyses above use deterministic steady state simulation to determine DG limits. It was shown that impacts on the dynamics of power systems can be positive or negative [8] and the impacts depend on a variety of factors related to the exact system topology [8, 9]. Because PV systems interface with the power system using power electronics, control techniques can be used to help mitigate some of the negative influence of PV [10].

The system in [5] did not consider factors such as phase imbalance, source impedance, and conductor resistance, which can be particularly important when analyzing isolated segments of distribution feeders. The detailed static modeling approach used in [7] is more appropriate for analyzing DG limits in isolated segments of distribution systems. This approach was used in [11] to determine limits of PV on single-phase laterals and secondaries of some distribution system constructions.

The factors that limit distributed PV deployment are similar to those that limit rotating DG. However, fuse saving and fault detection sensitivity considerations are less significant due to the lower fault current contributions from PV inverters. Furthermore, the performance requirements of residential secondaries should be considered when studying distributed PV. When PV is connected to a shared secondary (120/240-V) circuit, some jurisdictions require that the aggregate generating capacity on the secondary not exceed 10 to 20 kVA, and that the load imbalance between the two 120-V transformer secondary windings not exceed 20% of the nameplate rating [12].

2.0 DISTRIBUTED PV DEPLOYMENT LIMITS

A study documented in [11] analyzed limits of photovoltaic systems on single-phase laterals and secondaries of distribution systems. Three factors were found that could limit the deployment of distributed photovoltaic systems. The methods and results of that study are summarized and the resulting recommended guidelines are reviewed.

2.1 LIMITING FACTORS

The four factors that were considered when determining PV limits on single-phase laterals and secondaries of distribution systems are described in this section.

2.1.1 Voltage Rise

The addition of distributed generation to power systems has been shown to cause system voltage levels to rise [1, 8, 9, 13]. Voltage levels of distribution systems are subject to regulatory requirements [14]. Care should be taken when planning to add PV to distribution systems to ensure that regulatory limits are not exceeded.

In a radial distribution system, current flows from the source at the substation and each load. As the current flows through each conductor and transformer, the voltage drops according

to Ohm's law. Distribution system load levels vary over time. Higher load levels cause higher voltage drop.

The addition of distributed generation at a load site reduces or eliminates the effective load at that site, reducing the voltage drop across the distribution system components. If generation exceeds load, the effective load can be negative, causing current flow towards the substation and developing a negative voltage drop between the substation and the load. In either case, the difference between the voltage at a system node with PV and the voltage at that same node with no PV is referred to as voltage rise. Voltage rise particularly pronounced on secondaries where the distribution transformer has a relatively high impedance compared to the conductors. The worst case voltage rise occurs when the load has a minimum value and the PV output has a maximum value.

2.1.2 Capacity Limits

The capacity of a distribution segment refers to the amount of power or current that can be delivered through that segment. The capacity of a system can be limited by the thermal properties of conductors [5] and by overcurrent protection devices [7]. In some circumstances, the deployment of distributed generation can cause the current to increase beyond the design limits of the system.

When the level of distributed generation at a node greatly exceeds the peak load, the reverse current at times of peak generation and low load can exceed the peak forward current prior to distributed generation. At distribution system nodes with a high short circuit current and fed by a voltage source sufficiently below the acceptable upper voltage limit of 1.05per-unit,

deployment of distributed generation can cause the reverse current to exceed the thermal limit of the conductors before the voltage rise reaches its limit [5].

When a fault occurs on a distribution system, overcurrent protection devices (such as fuses) close to the fault are often used to isolate the faulted section of the circuit. In a radial system with no distributed generation, the fault current is supplied from the substation. Any distributed generation will supply fault current (up to the short circuit current rating of the generator) according to the equivalent impedance between the fault and the generator. This can cause undesired overcurrent protection device actuations. When a fault behind one device can be fed by a large distributed generator behind a different device, the overcurrent protection device closest to the distributed generator can actuate before the overcurrent protection device closest to the fault.

2.1.3 Load Balance

A power system with multiple phases is balanced if the magnitudes of the voltages and currents are uniform across the phases. Losses throughout a power system are lowest when all phases are balanced. When the loads are the same across each phase of a power system with balanced generation and distribution component impedance, the power system is balanced. Typically, the power supplied to a substation is reasonably well balanced. In addition, components in three-phase and split-phase segments of distribution systems have approximately balanced impedances for all phases. Load balance can be difficult due to customer behavior and geographic limitations, especially in distribution systems with single-phase laterals. The installation of single-phase distributed generation can change the effective load of one phase and increase the

imbalance of a system. This is true for both single-phase lateral deployment and split-phase secondary deployment.

2.2 OTHER CONCERNS

These additional factors could hypothetically limit PV deployment but were found not to be limiting factors under normal circumstances.

2.2.1 Harmonics

The switching components of PV inverters can inject harmonics onto the grid. Filters are included with PV systems to limit this injection of harmonics. However, the filters affect the resonance characteristics of the distribution system. In a study on harmonic resonance of multiple PV inverter filters [15], it was found that the resonance peak caused by low numbers of PV systems designed for normal filtering and damping was not of concern. Furthermore, at high penetration levels, the magnitude and frequency of the peak was reduced. The dynamic interactions between inverters from different manufacturers were not studied in this thesis. If the interactions between a specific set of inverters from different manufacturers is of concern, a dynamic study would be required.

2.2.2 Distributed Voltage Regulation

Distribution substations usually have voltage regulation equipment. For some feeders, especially long or heavily loaded feeders, voltage regulation at the substation is insufficient to ensure acceptable voltage throughout the feeder. In these cases, distributed voltage regulation equipment may be deployed to provide more localized voltage support. The impact of such devices within single-phase laterals would be difficult to generalize. Where present, distributed voltage regulation devices require an additional study when the total PV downstream of the device can exceed 100% of the aggregate downstream minimum load, because the resulting reverse power flow may cause voltage regulators to mis-operate. This issue usually occurs with large three-phase PV installations, not the smaller single-phase installations considered here.

2.2.3 Fuse Saving

Fuse saving refers to the practice of using an automatic recloser to briefly interrupt current to a larger section of a feeder with multiple branches, each protected by separate fuses. The brief interruption can clear temporary faults, before downstream fuses have to melt. While this practice causes a temporary service interruption to many customers, it can prevent much longer outages to a smaller number of customers.

Distributed generators downstream of a recloser can supply a portion of the fault current up to the short circuit current of the generator depending on the impedance between the generator and the fault. This reduces the portion of the fault current flowing through the recloser and can inhibit the ability of the recloser to detect the fault. Rotating DG up to levels limited by voltage rise and capacity limits were found not to interfere with fuse saving in [7]. PV

contributes less fault current than rotating DG; therefore, fuse coordination is not expected to limit the deployment of PV.

2.2.4 Islanding

An island in a power system is a segment that is disconnected from the main grid while power is supplied by distributed generators to distributed loads. In an unintentional island, the voltage and frequency regulation provided by the grid are absent and loads can be damaged. When the fuse of a single-phase lateral melts, an island is created for as long as distributed generators continue to operate. Anti-islanding screening guidelines are included in [16]. According to those guidelines, if any of the following are true, excessive islanding times are unlikely: (1) the inverter rating is less than two thirds of the aggregate minimum island load, (2) the reactive power load and generation in the island differ by more than 1% or (3) most of the distributed generation in the island is from inverters of similar make and size. When distributed PV systems are operated at unity power factor, any reactive power load will not be supplied in an island situation and PV inverters should be able to detect islands in an appropriate amount of time.

2.2.5 System Stability

In some power systems consisting of power-electronics-based generation, high levels of harmonics and a lack of a stiff system frequency have caused destabilization of the system [17]. When the power supplied to a distribution system lateral is dominated by distributed PV, these stability issues could occur. However, in a study on harmonic resonance of multiple PV inverter filters [15], it was found that PV systems designed for normal filtering and damping do not

increase harmonic resonance of distribution systems. Therefore, distributed PV inverters are not expected to cause stability issues on normal distribution systems. In some special cases, such as on laterals in very weak segments of the distribution system, additional high-PV penetration studies may be required. These studies might entail modeling system dynamics using a program like PSCAD and detailed vendor-specific inverter models. In order to protect intellectual property, vendors may wish to provide complied models, which mask the exact topology and controls of the inverter. This may make it prohibitively difficult to generalize the results of studies.

2.3 ANALYSIS METHODS

This section reviews the methods used to study distributed PV limits in single-phase laterals and distribution secondaries in [11].

2.3.1 Distribution Feeder Simulation

A configurable single-phase lateral was modeled using an open-source distribution system simulator called OpenDSS [18]. Steady-state simulations were performed with real power PV output of 100% and load levels of 30% for laterals and 20% for secondaries. This is meant to represent a conservative case where minimum load is assumed to be approximately one third of the maximum load for larger sections of the distribution system with additional variability accounted for in the secondary. PV systems were modeled in steady-state as generators with

negative real power load. OpenDSS was run in snapshot mode. Controlled components (like voltage regulators and capacitors) are allowed to operate until convergence is obtained and a steady-state load-flow solution is obtained. The modeling and analysis was automated by running the simulator from two spreadsheet interfaces. Simulation results were examined using the criteria discussed above.

2.3.2 Single-Phase Lateral Modeling

Single-phase laterals were modeled by connecting a source with equivalent impedance equal to the source impedance at the substation plus the calculated impedance between the substation and the head of the feeder. Loads and distributed PV were connected at specified intervals along the lateral as shown in Figure 5.

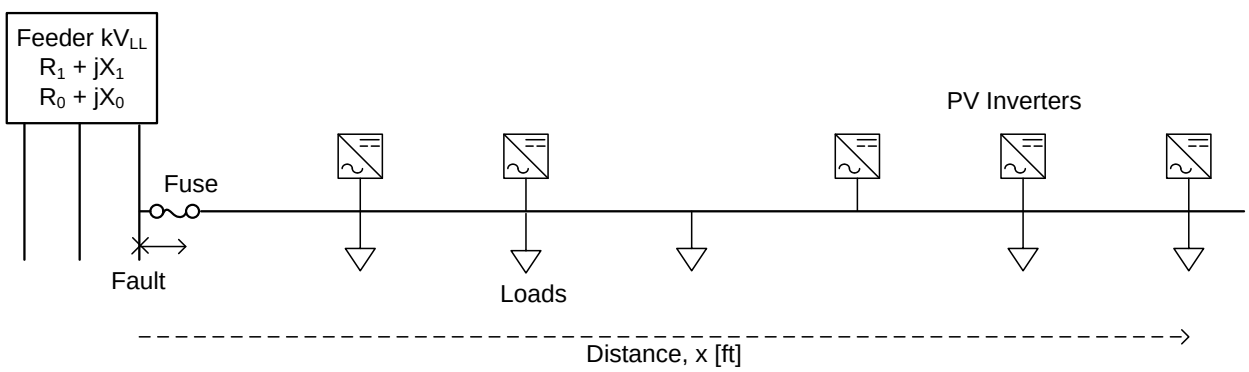

Figure 5. Single-phase lateral configuration with loads and PV inverters

Circuit parameters could be specified dynamically:

1) Feeder characteristics including primary voltage, substation transformer size and impedance, and conductor construction.

2) Distance from substation to single-phase lateral tap.

3) Fuse size.

4) Lateral conductor construction and length.

5) Aggregate maximum load of the lateral and load power factor.

6) PV inverter power factor and fault current contribution.

Selectable parameters were based on National Grid feeders. Primary conductor types included 1/0 AL, 1/0 CU, 2/0 AL, 4/0 CU, 336 AL, and 477 AL on horizontal crossarms, along with 336 AL and 477 AL on spacer cable (SPC). Data for the substation transformer and the predominant primary conductor along with the distance from the substation to the lateral were used to determine the distribution system impedance.

The lateral circuit parameters studied included:

1) 13.8-kV feeder fed from a 10-MVA, 7% substation transformer, 477 SPC construction.

2) Lateral tap point 1 mile or 5 miles from the substation bus.

3) Lateral fuse size 6, 10, 15 or 25 amps.

4) 1/0 or 2/0 AL lateral construction.

5) Aggregate maximum load up to 100% of the fuse rating, power factor of 0.85.

6) PV inverters at unity power factor, contributing up to 1.2 times nominal current to faults.

Voltage profiles of the laterals were analyzed along with the PV contributions to a fault on the main feeder. Per National Grid's interconnection requirements [12], Voltage was required to remain within 5% of nominal along the lateral, and the maximum voltage fluctuation was limited to 5%, PV fault contributions were not allowed to exceed the rating of the fuse. PV penetration was increased until one of these limits was reached and recommended limits on the total connected PV were developed.

2.3.3 Distribution Secondary Analysis

In order to model a distribution secondary in greater detail, one or more parallel service drops are connected to a split-phase distribution transformer. Loads and distributed PV are connected at specified intervals as shown in Figure 6.

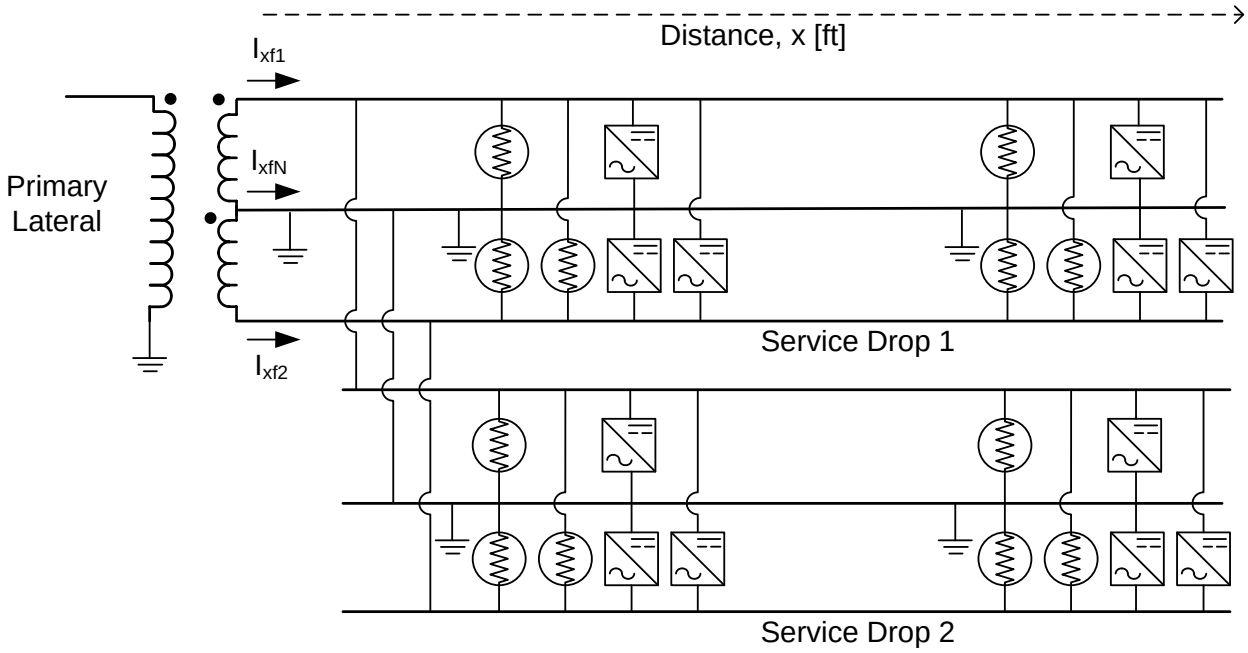

Figure 6. Split-phase distribution transformer with service drops, loads and PV inverters

Circuit parameters could be specified dynamically:

1) Distribution transformer characteristics including size and impedance.
2) Service drop construction and length.
3) Number of parallel service drops.
4) Aggregate maximum load and load power factor.
5) Percent unbalance of load.

6) PV inverter power factor and fault current contribution.

The distribution secondary circuit parameters studied included:

1) Transformer size 10, 25, or 50 kVA.
2) Secondary drop construction of #2 AL triplex full neutral, #1 AL triplex full neutral, and 1/0 AL triplex 1/3 neutral.
3) Either 1 or 2 parallel service drops.
4) Maximum load of 100 kVA, power factor of 0.85.
5) 10% customer load unbalance.
6) PV inverter characteristics as in lateral circuit analysis base case.

Both 240-V and 120-V PV systems were studied with unbalanced split-phase load. To prevent a reverse overload, PV ratings were not allowed to exceed the rating of the distribution transformer. As in the lateral analysis, voltage fluctuations were required to remain within 5% of the nominal value [12].

2.4 RESULTS

This section reviews the results developed in [11] and includes recommended guidelines for PV on single-phase laterals and secondaries of distribution systems.

2.4.1 Single-Phase Lateral Results

For the single-phase laterals studied, the size of the lateral fuse limits distributed PV penetration as shown in Table 1. Neither the conductor size nor the distance from substation affected these limits.

Table 1. Distributed PV Limits for Different Fuse Sizes

Fuse Size [A]	Conductor	Distance from Substation [mi]	Lateral Load [kW]	PV Limit [kW]
6	1/0 or 2/0 AL	1 to 5	48	40
10	1/0 or 2/0 AL	1 to 5	80	65
15	1/0 or 2/0 AL	1 to 5	120	100
25	1/0 or 2/0 AL	1 to 5	200	165

When PV deployment is less than the limits above, the voltage magnitudes and imbalance remained well within tolerance. See Figure 7 for an example. Vstep is the difference between the maximum voltage on the lateral with PV and the minimum voltage on the lateral without PV as a percentage of the nominal voltage. In this example, the voltage is always within 1% of the nominal value.

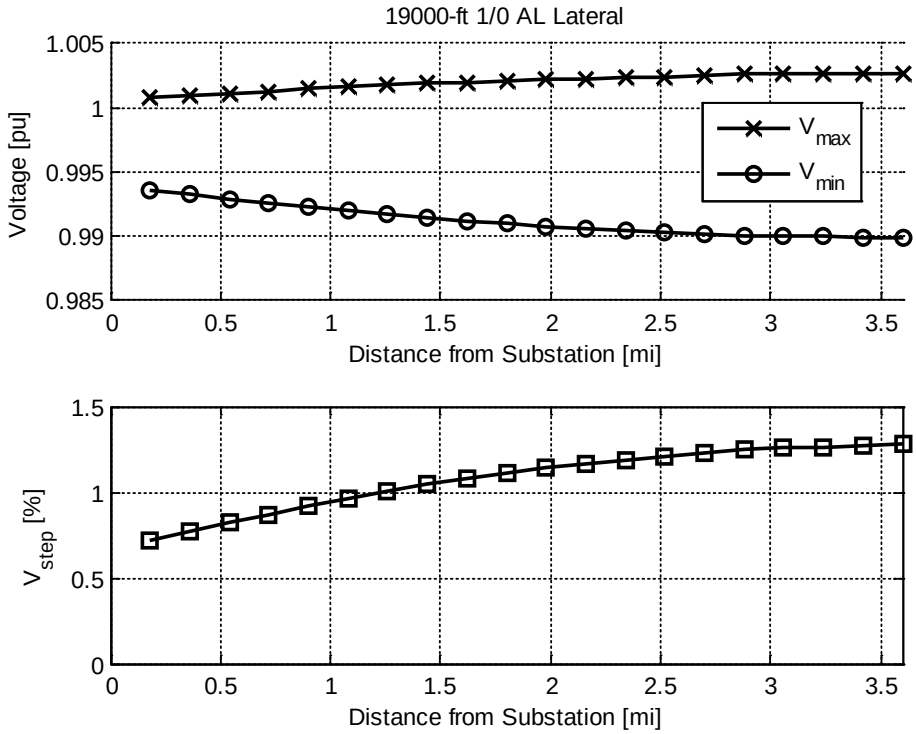

Figure 7. 19000-ft 1/0 AL lateral at 7.967 kV, 200 kW load and 165 kW PV

2.4.2 Distribution Secondary Results

Balanced 240-V PV could be deployed up to the size of the transformer. Assuming nominal voltage on the distribution transformer primary, the distance from the transformer was limited based on voltage rise along the service conductor (which depends on the conductor type). For 120-V PV inverters, the transformer load unbalance limit (20% of nameplate) and voltage unbalance limit (3%) determine the aggregate PV limit and maximum distance from the transformer. See Figure 8 for an example. The voltage unbalance is the difference between the voltage magnitudes of the positive and negative split-phase lines. In this example PV penetration is limited by the voltage unbalance limit.

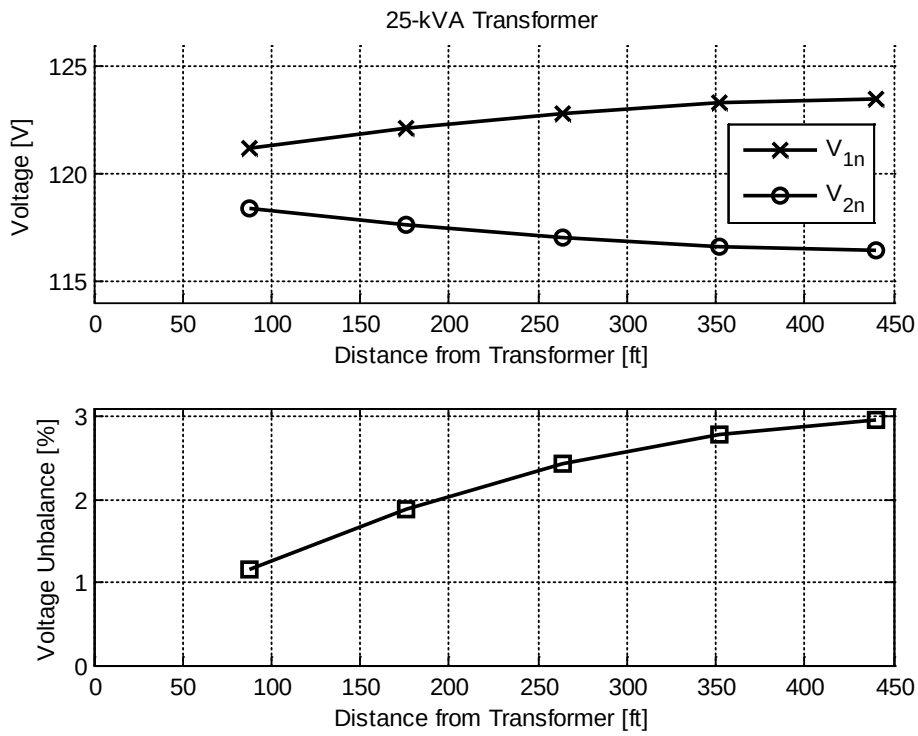

Figure 8. 25-kVA transformer, #1 AL triplex full neutral, 6.5 kW aggregate 120-V PV

Distributed PV and service drop length limits are shown in Table 2. Distance limits shown apply for #2 AL triplex full neutral secondary construction. Increasing the service drop conductor size from #2 to #1 increases the 120-V PV distance limits by 10% and the 240-V PV distance limits by 25%. Increasing the conductor size further, from #1 to 1/0, increases the 120-V PV distance limits by 10% and the 240-V PV distance limits by 25% yet again.

Table 2. Distributed PV and Service Drop Limits for Different Distribution Transformer Sizes

Transformer Size [kVA]	Min. Load [kW]	120-V PV Limit [kW]	Distance Limits [ft.]		
			120-V Limit PV, Evenly Spaced	120-V Limit PV, End of Drop	240-V PV of Xfmr Size End of Drop
10	2	2.5	1100	600	2000
25	5	6.5	400	225	800
50	10	13.0	175	105	400

3.0 CASE STUDIES OF SINGLE-PHASE LATERALS

This section documents case studies of hypothetical photovoltaic system deployments to single-phase laterals and secondaries of a utility distribution feeder. Four single-phase laterals were analyzed from an example distribution feeder in the FirstEnergy footprint. An OpenDSS model was created of the feeder using model conversion tools (See Appendix) developed for a distribution feeder analytics for distributed energy resource integration research collaboration between the University of Pittsburgh and FirstEnergy [19]. The guidelines developed in Section 2 were used as a starting point to perform hypothetical photovoltaic system deployment studies to single-phase laterals and secondaries of the modeled distribution feeder. The guidelines were developed by modeling single-phase that were representative of one utility's (National Grid's) systems. In this section, the guidelines are stress-tested by modeling single-phase laterals in a system of a different utility.

3.1 METHODOLOGY

3.1.1 Feeder Description

FirstEnergy is a large utility operating in parts of the Midwest and Mid-Atlantic United States. The distribution feeder used to develop the model for this analysis is FirstEnergy circuit Clinton-0056. This relatively large feeder was selected because it includes single-phase laterals with a range of characteristics and data available to model secondaries. Model conversion tools were used to generate an OpenDSS model of the feeder from Geographic Information System (GIS) data as described in the Appendix. Only overhead secondaries were considered. Load-flow simulations were performed with each load operating at 50% of its nominal summer peak. This load condition will be referred to as a “typical load” condition; it is meant to simulate reasonable but not necessarily actual feeder conditions.

Figure 9 shows the layout of the feeder with line thickness weighted according to the relative power flow through each segment for a normal power flow solution.

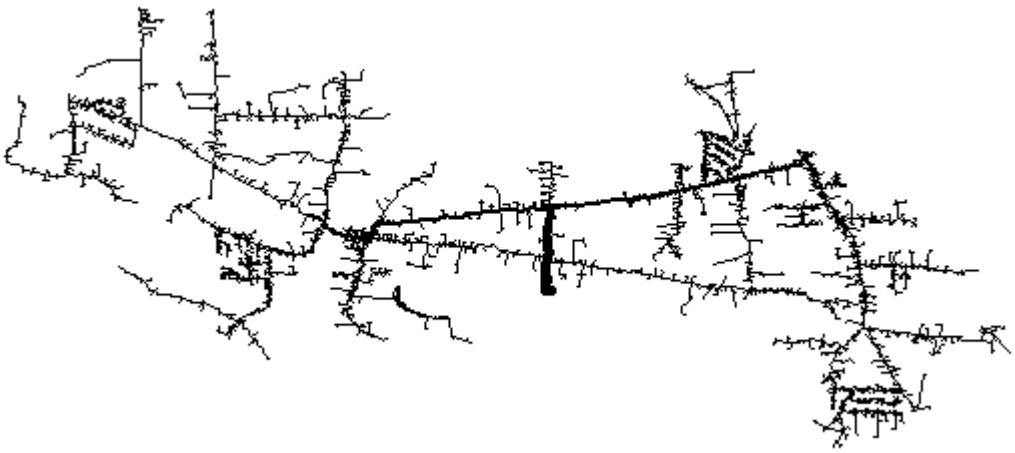

Figure 9. Case Feeder Topology

The thickest line segment represents the substation and is located at the bottom of the middle of Figure 9. The substation voltage regulator was set to 1.04 per-unit to ensure that all primary nodes were within ANSI [14] limits. Figure 10 shows the voltage profile of the primary of the Clinton-0056 feeder model. The maximum voltage occurs at the substation and the minimum voltage occurs farthest from the substation. The voltage generally decreases with distance from the substation. In addition, the voltage unbalance generally increases with distance from the substation.

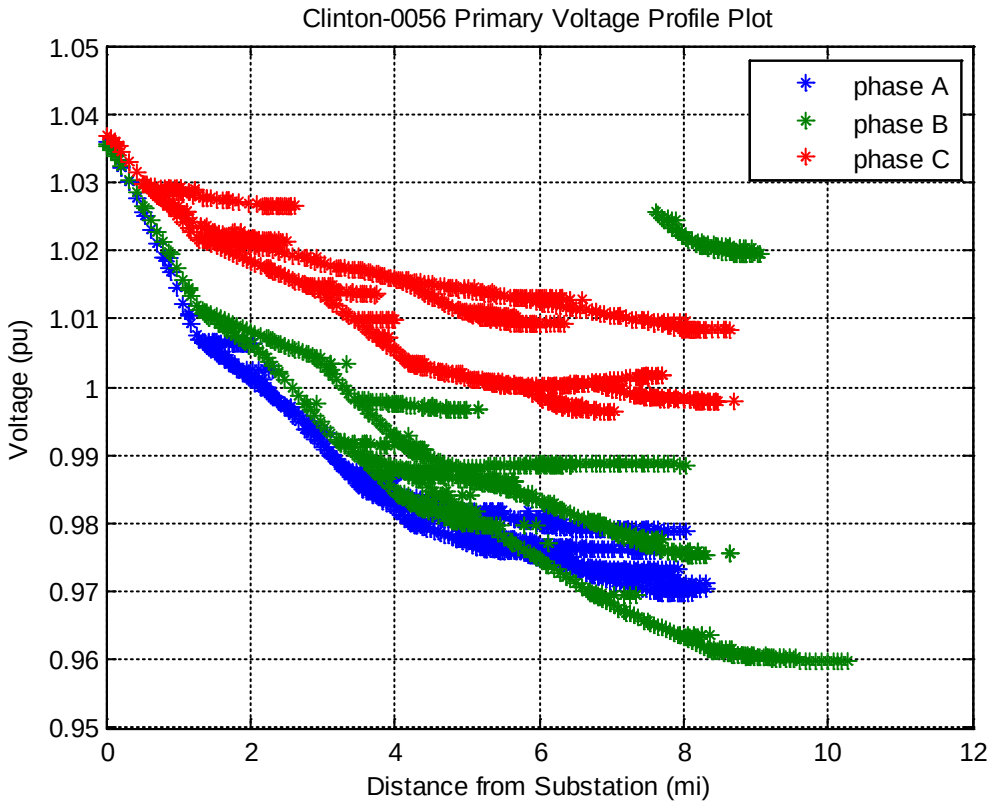

Figure 10. Case Feeder Voltage Profile under Typical Load

The OpenDSS model of the Clinton-0056 circuit used for this analysis has the following attributes:

- Number of Customers: 3611
- Number of Distribution Transformers: 758
- Total Power (from normal load-flow): 4.90-MW
- Maximum distance from substation: 10.4 mi.

3.1.2 Summary of Laterals

Four single-phase laterals were selected from the Clinton-0056 feeder. The laterals were selected from each phase of the system. They have a range of fuse sizes, distances from the substation, power consumptions, voltages, and Thevenin impedances. Some characteristics of each lateral are summarized in Table 3.

Table 3. Lateral Characterization

#	Color	ph	Fuse	Conductor Type	Dist (mi)	P-typ (kW)	V-typ (pu)	Xth-calc (ohm)	Rth-calc (ohm)
1	Red	1	10-A	#2 AL	5.868	1.45	0.980	4.31	2.29
2	Blue	2	25-A	#4 ACSR	6.671	6.88	0.980	4.69	2.82
3	Pink	3	25-A	1/0 ACSR	0.869	0.957	1.03	1.15	0.482
4	Green	2	40-A	Mixed	3.262	22.1	0.992	2.63	1.53

Additional discussion of each lateral is given later in its corresponding section. The location of each single-phase lateral on the Clinton-0056 feeder is highlighted on the system diagram in Figure 11.

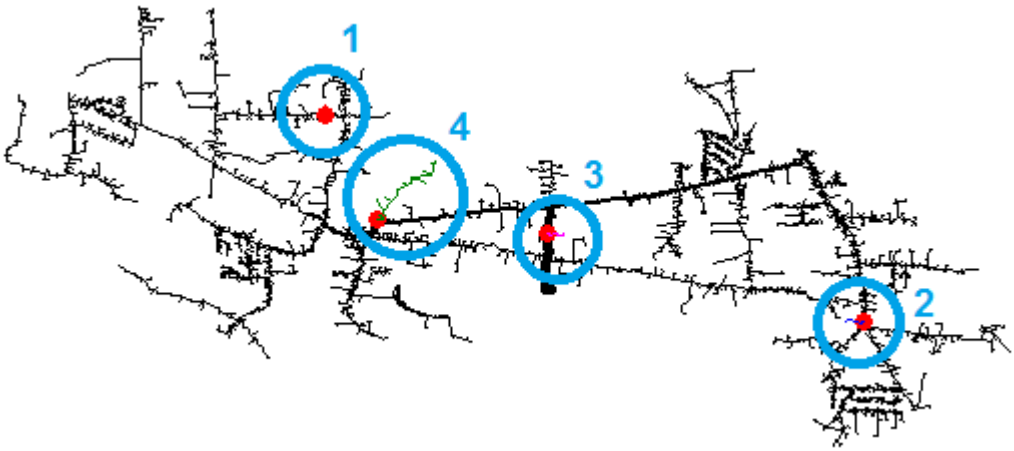

Figure 11. Locations of Laterals on Clinton-0056

3.2 LATERAL #1

Figure 12. Lateral #1 Topology

Lateral #1 is located in the upper-left quadrant of Figure 11. It is protected by a 10-A fuse and is about 5.9 miles from the substation. Lateral #1 is moderately far from the substation; it has a relatively high Thevenin impedance. The voltage at the head of the lateral is 0.980-pi. Lateral #1 has the smallest fuse of the laterals studied in Section 3. These and other characteristics are summarized in Table 4.

Table 4. Characterization of Lateral #1

#	Color	ph	Fuse	Conductor Type	Dist (mi)	P-typ (kW)	V-typ (pu)	Xth-calc (ohm)	Rth-calc (ohm)
1	Red	1	10-A	#2 AL	5.868	1.45	0.980	4.31	2.29

Figure 13 shows the voltage profile of Lateral #1 under typical load conditions.

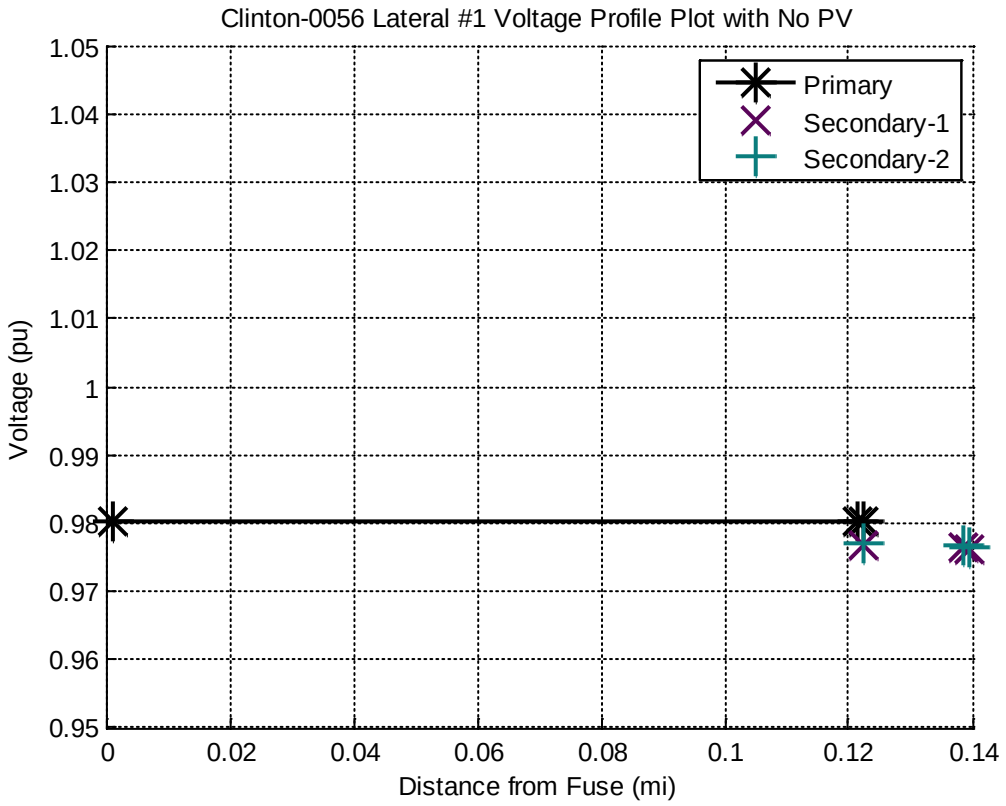

Figure 13. Lateral #1 Voltage Profile under Typical Load

3.2.1 Base Case for PV Analysis

Figure 14 shows the voltage profile for Lateral #1 under light load conditions. The voltage of the lateral is more than 0.05 per-unit higher than the typical load case and is much closer to the substation regulator set-point of 1.04 per-unit.

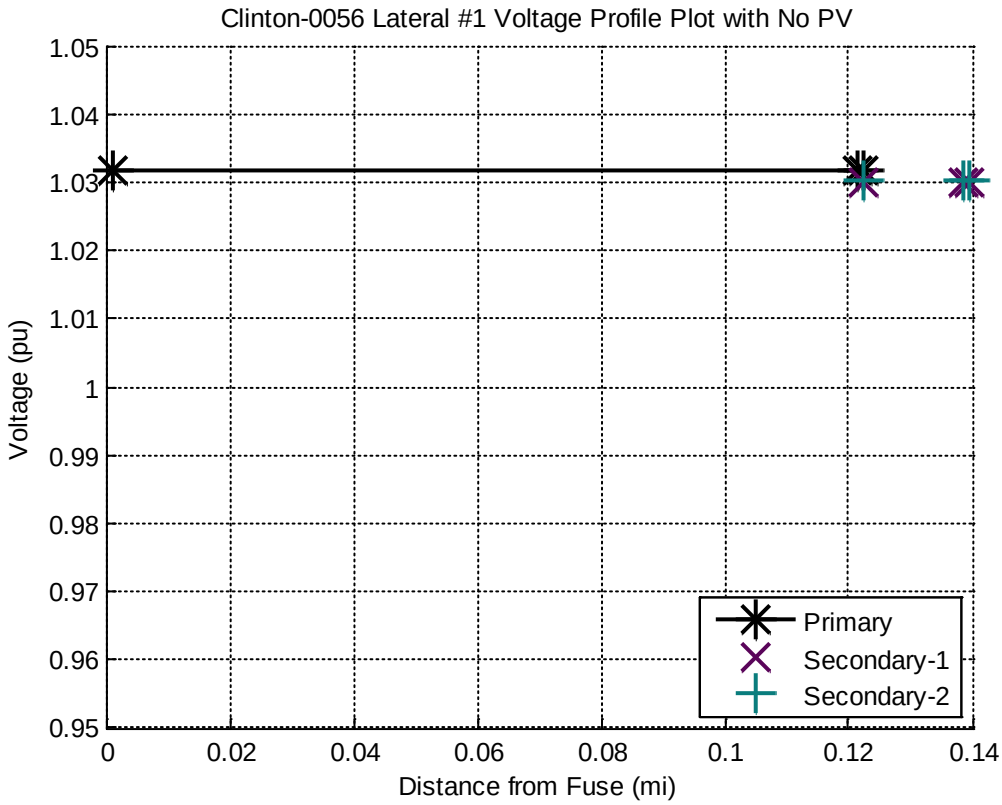

Figure 14. Lateral #1 Voltage Profile under Light Load

3.2.2 PV Deployment to Primary

According to the guidelines developed in Section 2, the limiting factor for PV deployment to a fused single-phase lateral is the size of the fuse. The combined fault current contribution from all PV systems on a lateral was not allowed to exceed the operating current of the fuse. Lateral #1 is protected by a 10-A fuse.

The guidelines state that for a 13.8-kV feeder, PV is limited to 65-kW for a 10-A fuse, with a 5% reduction required for a 13.2-kV feeder. Because the Clinton-0056 feeder operates at 12.47-kV, an additional reduction is required. The guideline is based on a comparison of the fuse

rating to the fault current rating of the PV system, assuming a PV system fault current contribution of 1.2 per-unit.

$$I_{PV}^{fault} = \frac{S_{PV}}{V_{LN}} * 1.2 \leq I_{fuse} \tag{1}$$

Rearranging the equation above, the estimated maximum PV rating can be obtained.

$$S_{PV}^{max} = V_{LN} * I_{fuse} = \frac{12.47\ kV}{\sqrt{3}} * \frac{10\ A}{1.2} = 60\ kVA \tag{2}$$

A load-flow solution was performed with a 60-kVA PV system operating at unity power factor installed on lateral #1. The PV system was located at the primary node farthest from the beginning of the lateral. Figure 15 shows the voltage profile of Lateral #1 for the simulation described.

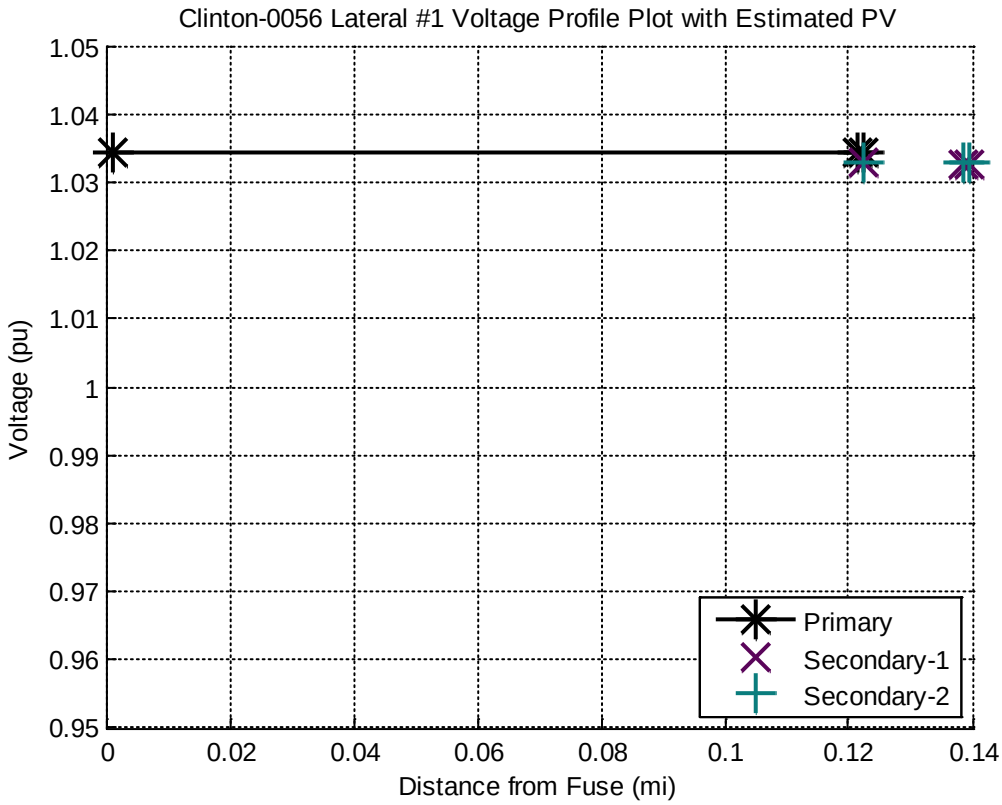

Figure 15. Lateral #1 Voltage Profile with 60-kW of PV

As seen above, the installation of 60-kW of PV has a limited impact on the voltage profile of Lateral #1. The maximum voltage on the lateral with the PV installation is 1.0345 per-unit compared to 1.0318 per-unit with no PV. This is a difference of 0.0027 per-unit. The limit established in Section 2 for PV on the primary of a single-phase lateral was found to be valid for Lateral #1 in this study.

3.2.3 Sensitivity of PV Deployment to Primary

The lateral fuse was found to limit the PV that could be deployed to Lateral #1. A sensitivity analysis was performed to determine approximately how much PV could be installed before the

lateral voltage exceeded 1.05 per-unit. Figure 16 shows the voltage profile of Lateral #1 with a significantly larger PV system installed.

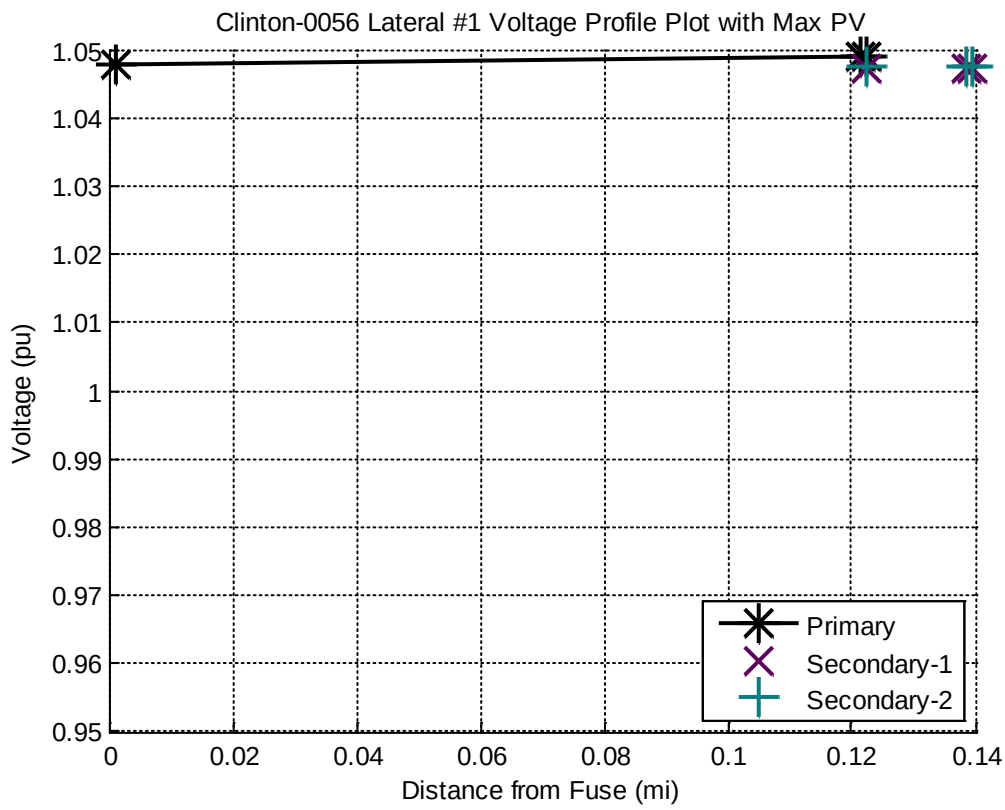

Figure 16. Lateral #1 Voltage Profile with 400-kW of PV

It was found that, under the conditions of this study, Lateral #1 could accommodate 400-kW before the lateral voltage exceeded 1.05 per-unit.

3.2.4 240-V PV Deployment to Secondary

According to the guidelines developed in Section 2, the limiting factor for 240-V PV deployment to distribution secondary is the size of the distribution transformer. The guidelines state that 240-

V PV is allowed up to a combined aggregate rating equal to the transformer rating. For a 25-kVA transformer, the distance from the transformer to the PV system is limited to 800.feet for #2 AL Triplex conductors with an increase of 55% for 1/0 AL Triplex conductors.

The secondary studied on Lateral #1 was supplied by a 25-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 53.3-ft, which is less than the allowable 1240-ft. Figure 17 shows the voltage profile for Lateral #1 with 25-kW of 240-V PV installed on the secondary.

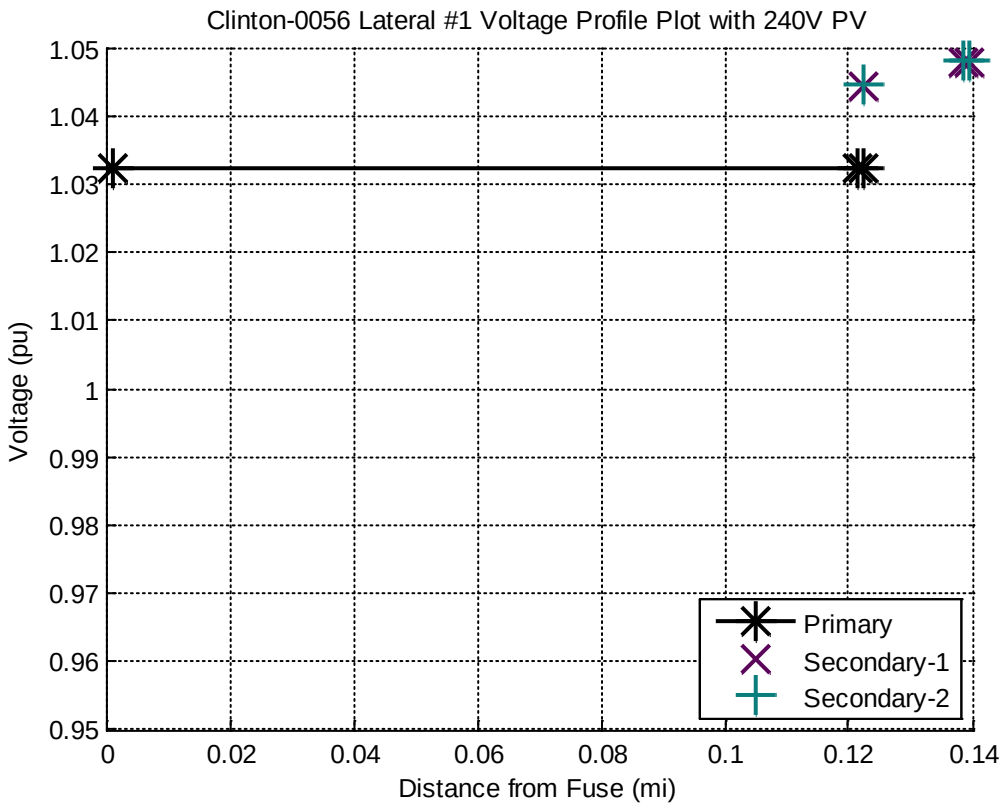

Figure 17. Lateral #1 Voltage Profile with 25-kW of 240-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by as much as 0.0159 per-unit. Neither the primary nor the secondary voltage ever exceeded 1.05

per-unit. The limit established in Section 2 for 240-V PV on the secondary of a single-phase lateral was found to be valid for Lateral #1 in this study.

3.2.5 120-V PV Deployment to Secondary

According to the guidelines developed in Section 2, 120-V PV deployment to a distribution secondary is limited by the size of the distribution transformer. For a 25-kVA transformer, the limit was 6.5 kVA. The distance from the transformer to the PV system is limited to 225 feet for #2 AL Triplex conductors with an increase of 20% for 1/0 AL Triplex conductors.

The secondary studied on Lateral #1 was supplied by a 25-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 53.3 feet which is less than the allowable 1240-ft. Figure 18 shows the voltage profile for Lateral #1 with 6.5-kW of 120-V PV installed on the secondary.

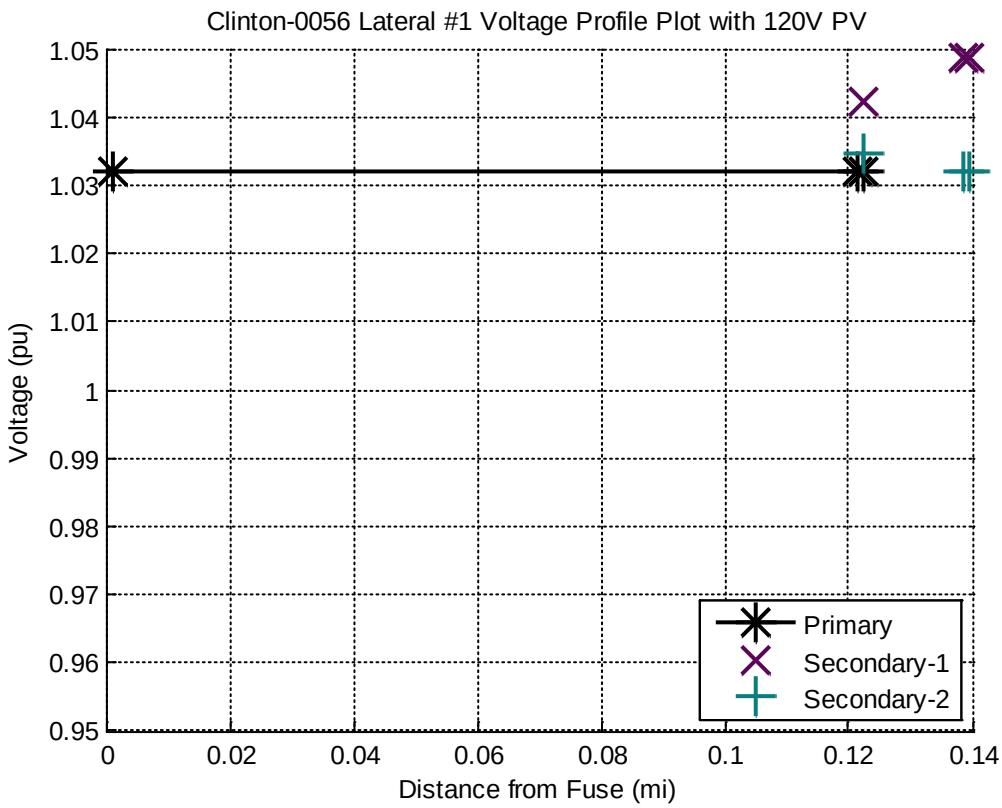

Figure 18. Lateral #1 Voltage Profile with 6.5-kW of 120-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by 0.0167 per-unit. The secondary imbalance was as high as 1.67%. Neither the primary, nor the secondary voltage ever exceeded 1.05 per-unit. The limit established in Section 2 for 120-V PV on the secondary of a single-phase lateral was found to be valid for Lateral #1 in this study.

3.3 LATERAL #2

Figure 19. Lateral #2 Topology

Lateral #2 is located in the lower-right quadrant of Figure 11. It is protected by a 25-A fuse and is 6.71 miles from the substation. Lateral #2 is the farthest lateral from the substation studied in Section 3 and it has the highest Thevenin impedance. The voltage at the head of the lateral is 0.980 per-unit. These and other characteristics are summarized in Table 5.

Table 5. Characterization of Lateral #2

#	Color	ph	Fuse	Conductor Type	Dist (mi)	P-typ (kW)	V-typ (pu)	Xth-calc (ohm)	Rth-calc (ohm)
2	Blue	2	25-A	#4 ACSR	6.671	6.88	0.980	4.69	2.82

Figure 20 shows the voltage profile of Lateral #2 under typical load conditions.

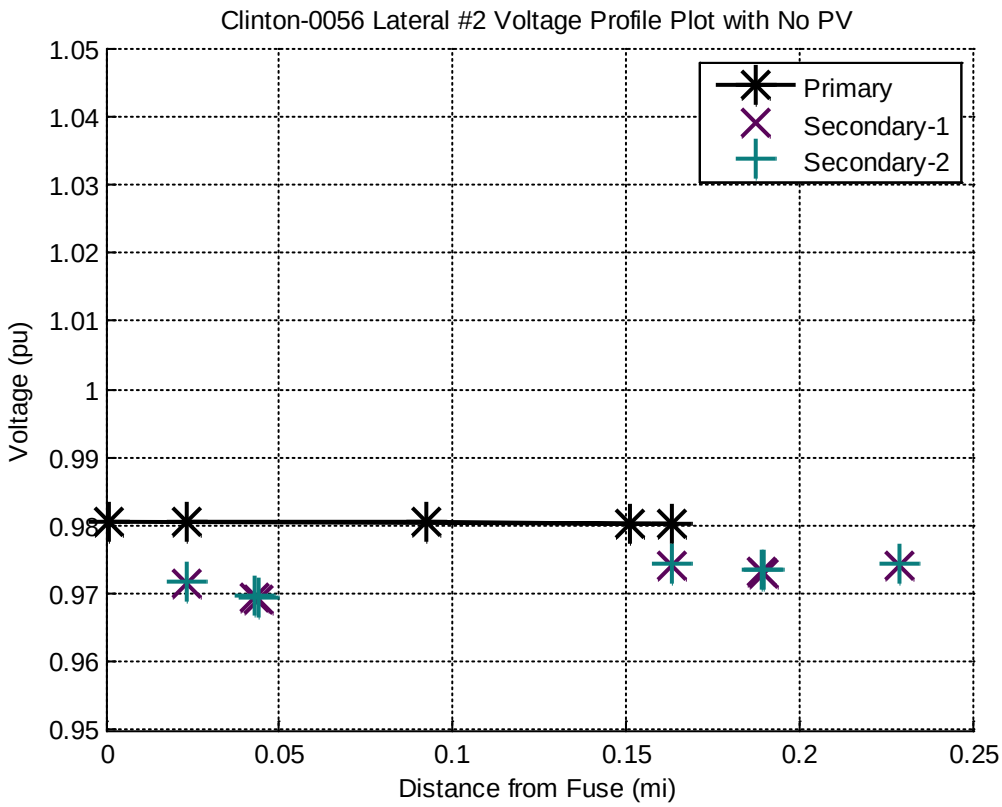

Figure 20. Lateral #2 Voltage Profile under Typical Load

3.3.1 Base Case for PV Analysis

Figure 21 shows the voltage profile for Lateral #2 under light load conditions. The voltage of the lateral is more than 0.05 per-unit higher than the typical load case and is much closer to the substation regulator set-point of 1.04per-unit.

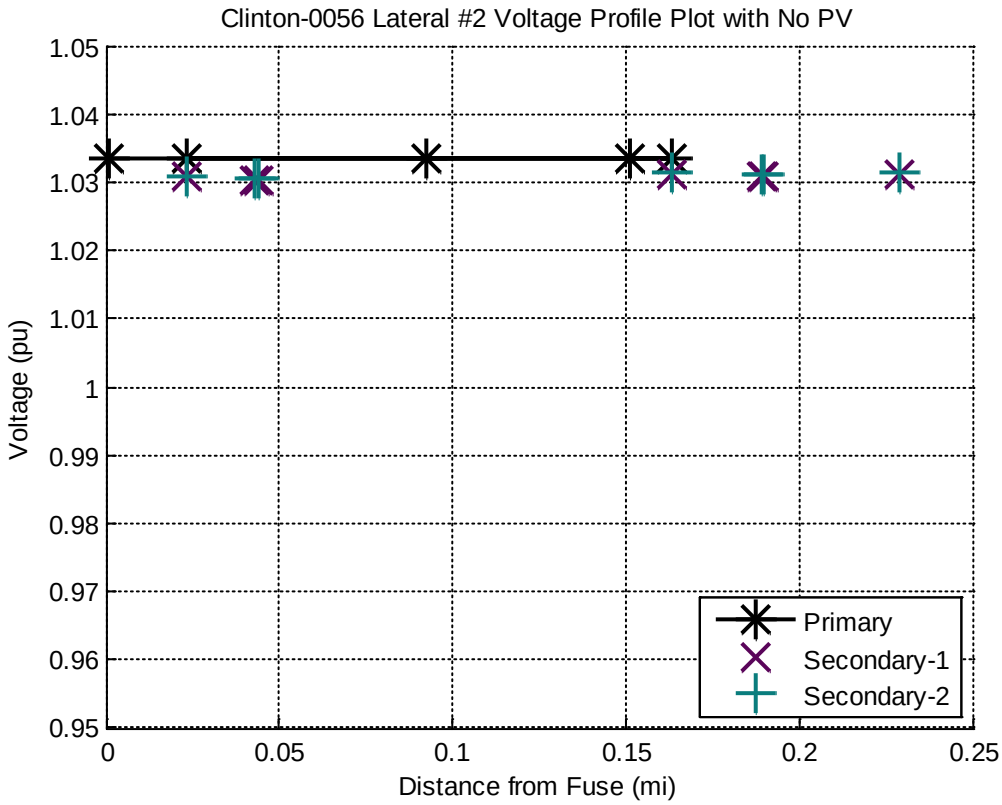

Figure 21. Lateral #2 Voltage Profile under Light Load

3.3.2 PV Deployment to Primary

According to the guidelines developed in Section 2, the limiting factor for PV deployment to a fused single-phase lateral is the size of the fuse. The combined fault current contribution from all PV systems on a lateral was not allowed to exceed the rating of the fuse. Lateral #2 is protected by a 25-A fuse.

The guidelines state that for a 13.8-kV feeder, PV is limited to 165-kW for a 25-A fuse, with a 5% reduction required for a 13.2-kV feeder. Because the Clinton-0056 feeder operates at 12.47-kV, an additional reduction is required. The guideline is based on a comparison of the fuse

rating to the fault current rating of the PV system, assuming a PV system fault current contribution of 1.2 per-unit.

$$I_{PV}^{fault} = \frac{S_{PV}}{V_{LN}} * 1.2 \leq I_{fuse} \tag{3}$$

Rearranging the equation above, the estimated maximum PV rating can be obtained.

$$S_{PV}^{max} = V_{LN} * I_{fuse} = \frac{12.47\ kV}{\sqrt{3}} * \frac{25\ A}{1.2} = 150\ kVA \tag{4}$$

A load-flow solution was performed with a 150-kVA PV system operating at unity power factor installed on Lateral #2. The PV system was located at the primary node farthest from the beginning of the lateral. Figure 22 shows the voltage profile of Lateral #2 for the simulation described.

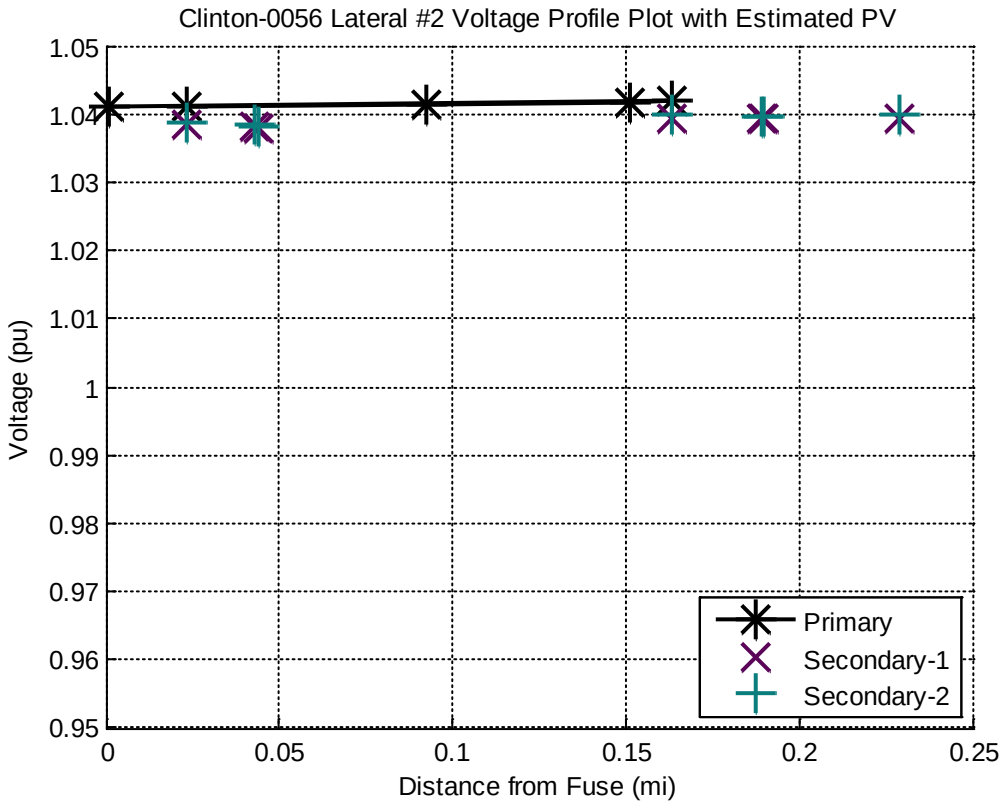

Figure 22. Lateral #2 Voltage Profile with 150-kW of PV

As seen above, the installation of 150-kW of PV has some impact on the voltage profile of Lateral #2. The voltage at the end of the lateral is visibly higher than the voltage at the head of the lateral. The maximum voltage on the lateral with the PV installation is 1.0418 per-unit compared to 1.0335 per-unit with no PV. This is a difference of 0.0083 per-unit. The limit established in Section 2 for PV on the primary of a single-phase lateral was found to be valid for Lateral #2 in this study.

3.3.3 Sensitivity of PV Deployment to Primary

The lateral fuse was found to limit the PV that could be deployed to Lateral #2. A sensitivity analysis was performed to determine approximately how much PV could be installed before the lateral voltage exceeded 1.05 per-unit. Figure 23 shows the voltage profile of Lateral #2 with a significantly larger PV system installed.

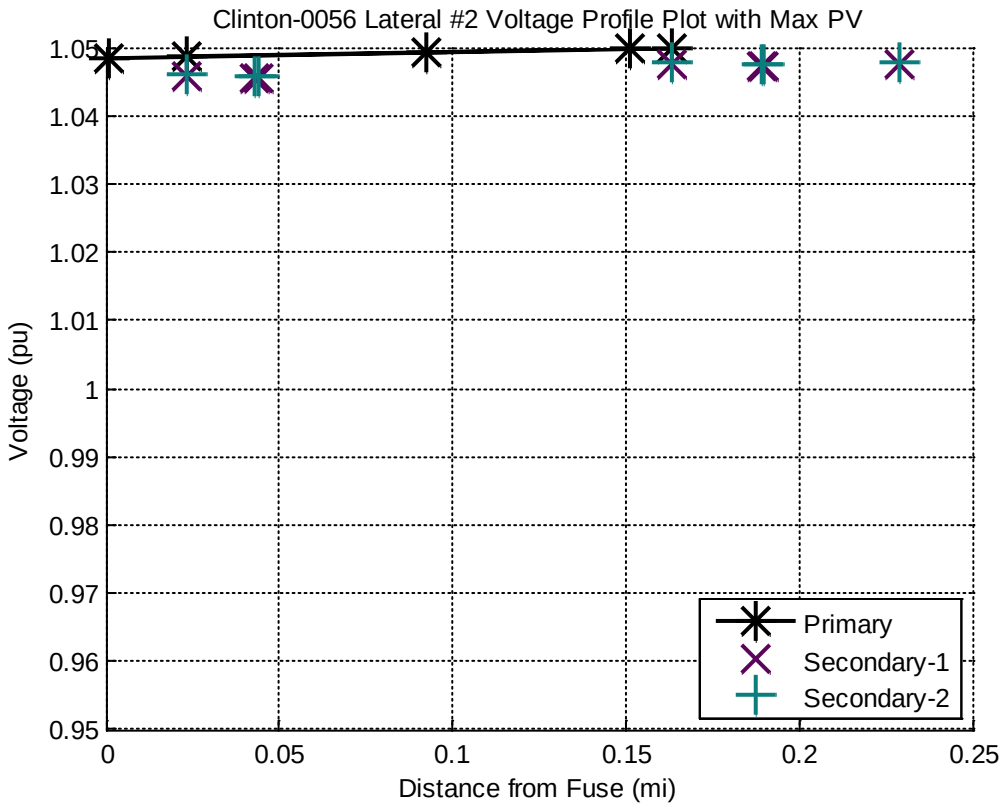

Figure 23. Lateral #2 Voltage Profile with 300-kW of PV

It was found that, under the conditions of this study, Lateral #2 could accommodate 300-kW before the lateral voltage exceeded 1.05 per-unit.

3.3.4 240-V PV Deployment to Secondary

According to the guidelines developed in Section 2, the limiting factor for 240-V PV deployment to distribution secondary is the size of the distribution transformer. The guidelines state that 240-V PV is allowed up to a combined aggregate rating equal to the transformer rating.

For a 25-kVA transformer, the distance from the transformer to the PV system is limited to 800 feet for #2 AL Triplex conductors. For a 10-kVA transformer, the distance from the transformer to the PV system is limited to 2000-ft for #2 AL Triplex conductors. In each case, an increase of 55% is allowed for 1/0 AL Triplex conductors. Larger transformers have a shorter maximum allowable distance from the transformer due to the larger PV system ratings allowed.

The secondary studied on Lateral #1 was supplied by a 15-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 215 feet which is less than the 1240 feet that would be allowed for a 25-kVA transformer. Figure 24 shows the voltage profile for Lateral #1 with 25-kW of 240-V PV installed on the secondary.

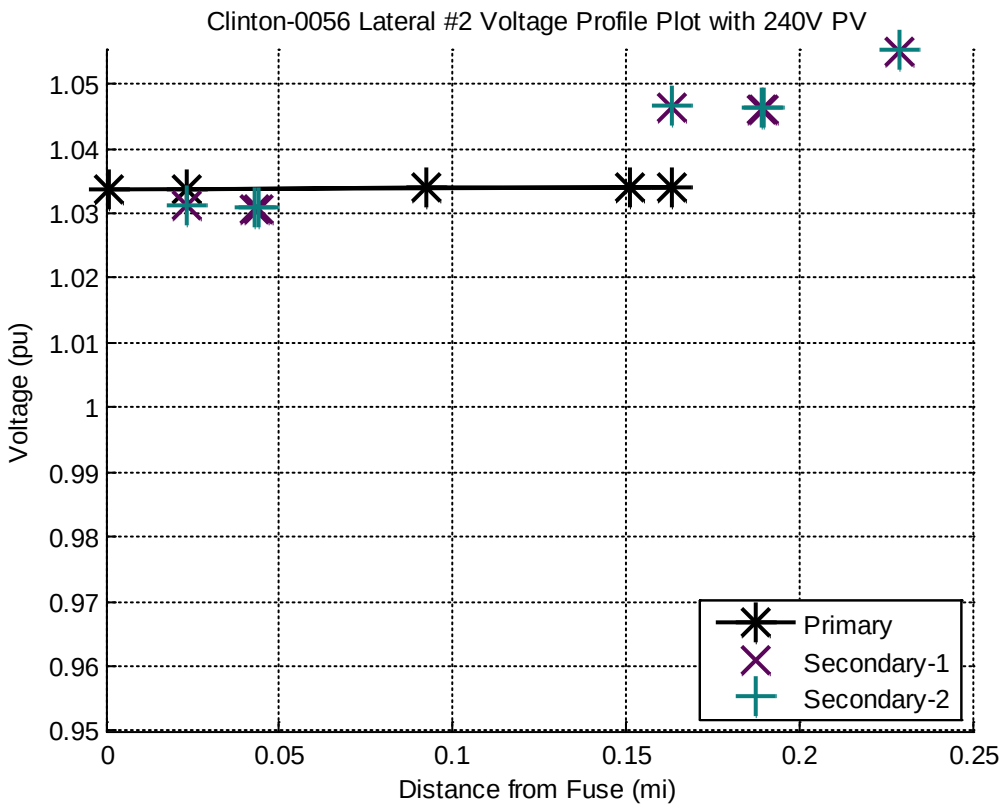

Figure 24. Lateral #2 Voltage Profile with 15-kW of 240-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by a 0.0216 per-unit. The voltage of Lateral #2 reached a maximum of 1.0554per-unit in this study. The limits in Section 2 were developed by limiting the voltage rise caused by the introduction of PV. This was based on a desire to keep the voltage on the feeder below 1.05 per-unit, which in turn requires the assumption that the voltage at the head of the lateral would be close to 1.0 per-unit prior to the introduction of PV. This study suggests that limiting the voltage rise caused by the PV will not always be sufficient for all laterals.

3.3.5 120-V PV Deployment to Secondary

According to the guidelines developed in Section 2, 120-V PV deployment to a distribution secondary is limited by the size of the distribution transformer. For a 25-kVA transformer, the limit was 6.5-kVA with the distance from the transformer to the PV system limited to 225 feet for #2 AL Triplex conductors. For a 10-kVA transformer, the limit was 2.5-kVA with the distance from the transformer to the PV system limited to 600 feet for #2 AL Triplex. In each case, an increase in the distance of 20% was allowed for 1/0 AL Triplex conductors.

The secondary studied on Lateral #2 was supplied by a 15-kVA transformer. The construction of the secondary is 1/0 AL Triplex. A linear interpolation between the 10-kVA and 25-kVA transformers suggests a limit of 3.8-kVA. For this study, the distance from the transformer to the PV site is 215 feet, which is less than the allowable 270 feet permitted for a 25-kVA transformer. Figure 25 shows the voltage profile for Lateral #2 with 3.8-kW of 120-V PV installed on the secondary.

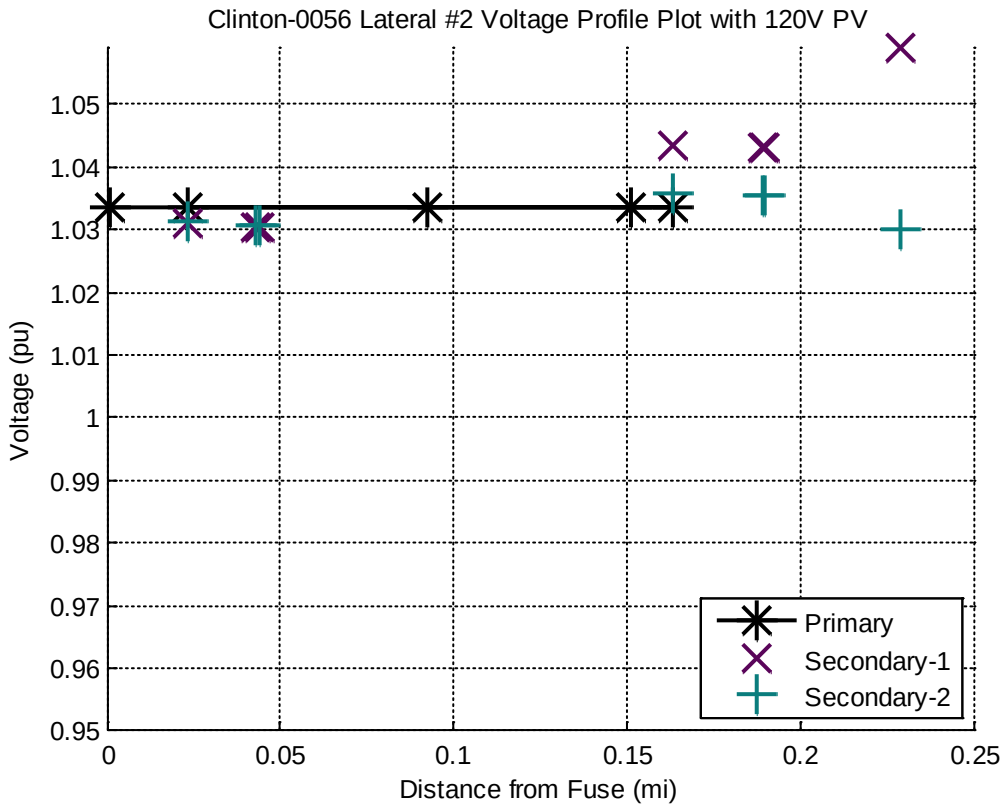

Figure 25. Lateral #1 Voltage Profile with 3.8-kW of 120-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by 0.0252 per-unit. The secondary imbalance was as high as 2.88%. The voltage of Lateral #2 reached a maximum of 1.0589per-unit in this study. The limits of Section 2 were developed by limiting the voltage rise and the secondary imbalance caused by the introduction of PV. This was based on a desire to keep the voltage on the feeder below 1.05 per-unit and requires the assumption that the voltage at the head of the lateral would be close to 1.0per-unit prior to the introduction of PV. This study suggests that limiting the voltage rise and secondary imbalance caused by the PV will not always be sufficient for all laterals.

3.4 LATERAL #3

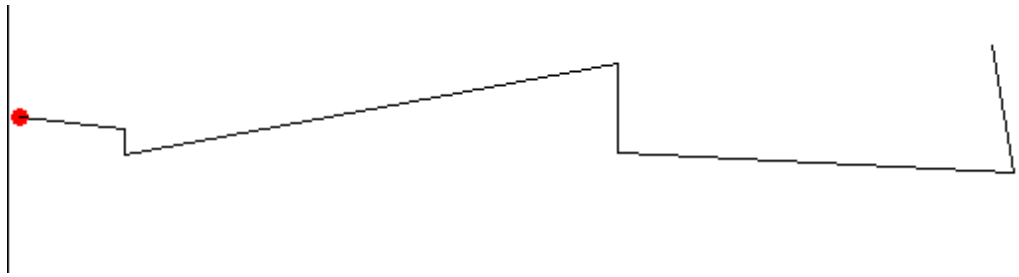

Figure 26. Lateral #3 Topology

Lateral #3 is located in the center of Figure 11. It is protected by a 25-A fuse and is about 0.87 miles from the substation, making it the closest lateral to the substation studied in Section 3; it has, by far, the lowest Thevenin impedance. The voltage at the head of the lateral is relatively high at 1.026 per-unit. These and other characteristics are summarized in Table 6.

Table 6. Characterization of Lateral #3

#	Color	ph	Fuse	Conductor Type	Dist (mi)	P-typ (kW)	V-typ (pu)	Xth-calc (ohm)	Rth-calc (ohm)
3	Pink	3	25-A	1/0 ACSR	0.869	0.957	1.03	1.15	0.482

Figure 27 shows the voltage profile of Lateral #3 under typical load conditions.

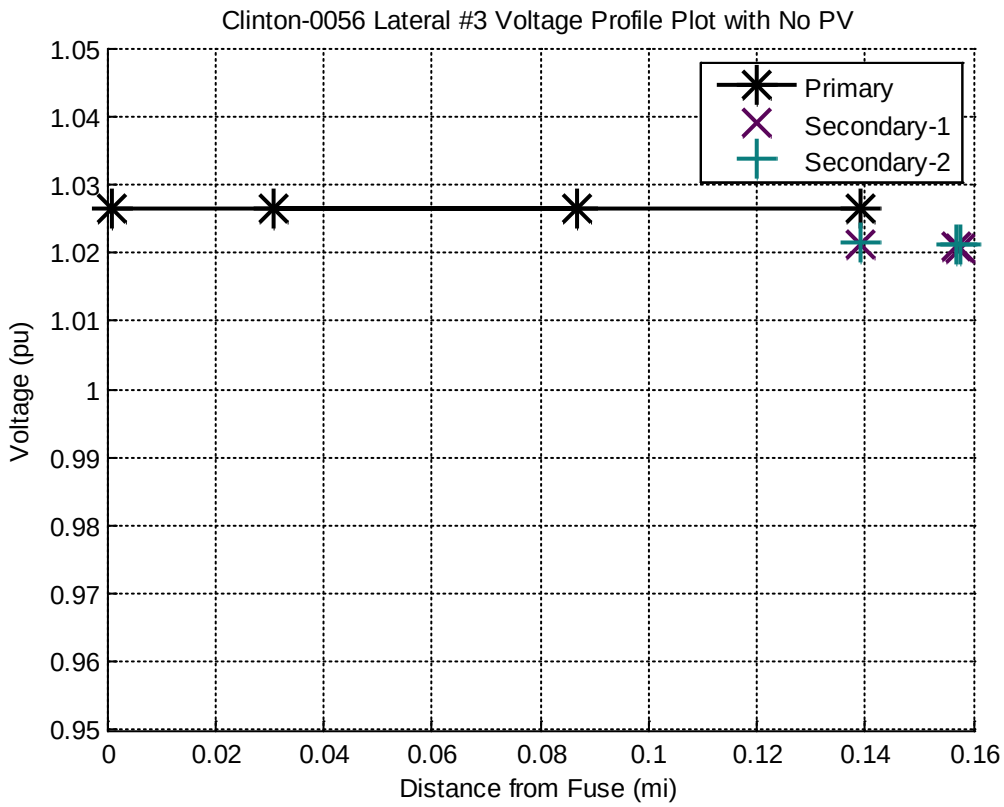

Figure 27. Lateral #3 Voltage Profile under Typical Load

3.4.1 Base Case for PV Analysis

Figure 28 shows the voltage profile for Lateral #3 under light load conditions. The voltage of the lateral is 0.05 per-unit higher than the typical load case and is much closer to the substation regulator set-point of 1.04 per-unit.

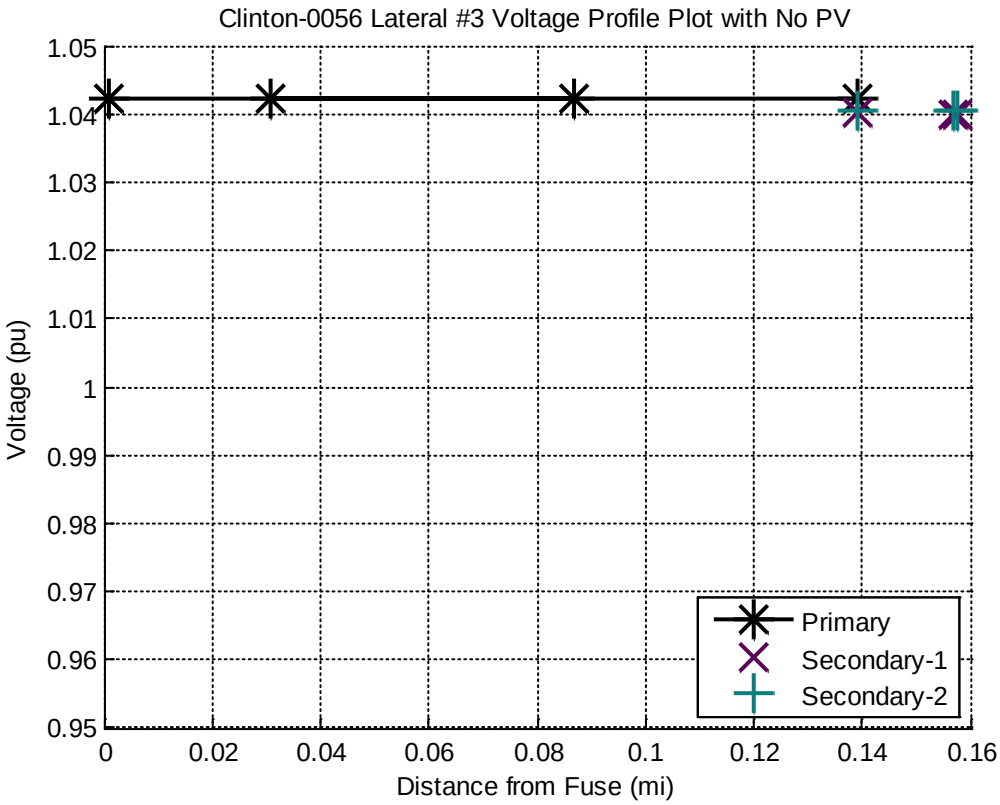

Figure 28. Lateral #3 Voltage Profile under Light Load

3.4.2 PV Deployment to Primary

According to the guidelines developed in Section 2, the limiting factor for PV deployment to a fused single-phase lateral is the size of the fuse. The combined fault current contribution from all PV systems on a lateral was not allowed to exceed the rating of the fuse. Lateral #3 is protected by a 25-A fuse.

The guidelines state that for a 13.8-kV feeder, PV is limited to 165-kW for a 25-A fuse, with a 5% reduction required for a 13.2-kV feeder. Because the Clinton-0056 feeder operates at 12.47-kV, an additional reduction is required. The guideline is based on a comparison of the fuse

rating to the fault current rating of the PV system, assuming a PV system fault current contribution of 1.2 per-unit.

$$I_{PV}^{fault} = \frac{S_{PV}}{V_{LN}} * 1.2 \leq I_{fuse} \tag{5}$$

Rearranging the equation above, the estimated maximum PV rating can be obtained

.

$$S_{PV}^{max} = V_{LN} * I_{fuse} = \frac{12.47\ kV}{\sqrt{3}} * \frac{25\ A}{1.2} = 150\ kVA \tag{6}$$

A load-flow solution was performed with a 150-kVA PV system operating at unity power factor installed on lateral #3. The PV system was located at the primary node farthest from the beginning of the lateral. Figure 29 shows the voltage profile of Lateral #3 for the simulation described.

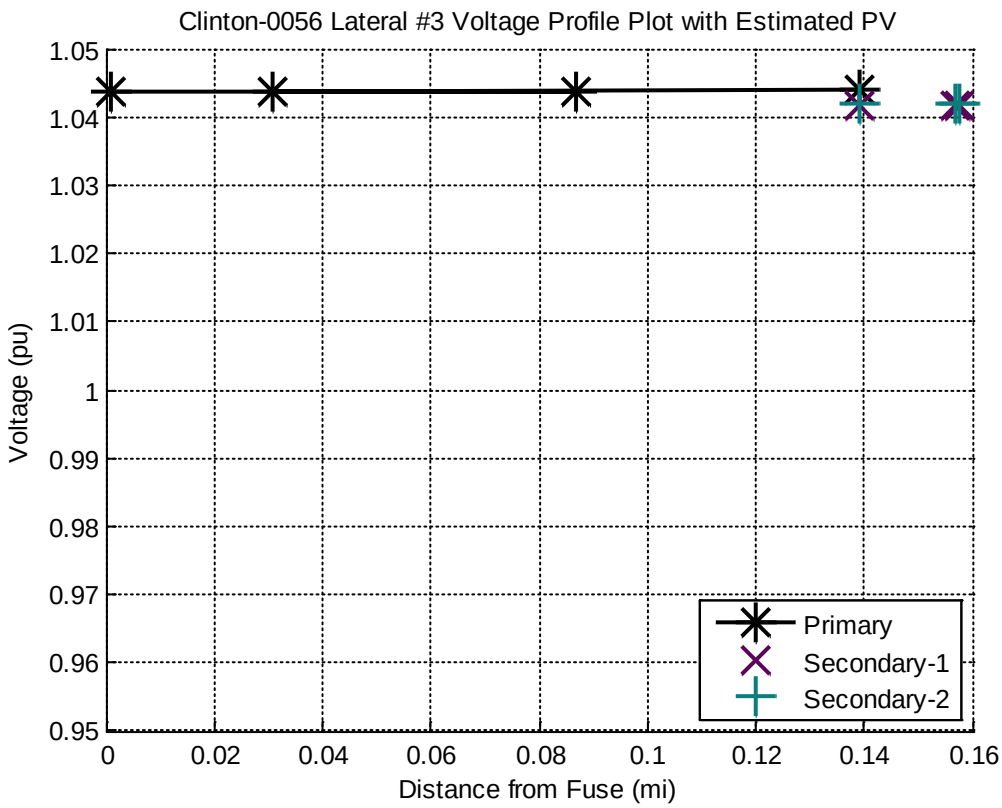

Figure 29. Lateral #3 Voltage Profile with 150-kW of PV

As seen above, the installation of 150-kW of PV has some impact on the voltage profile of Lateral #3. The voltage at the end of the lateral is higher than the voltage at the head of the lateral. The maximum voltage on the lateral with the PV installation is 1.0440 per-unit, compared to 1.0424 per-unit with no PV. This is a difference of 0.0016 per-unit. The limit established in Section 2 for PV on the primary of a single-phase lateral was found to be valid for Lateral #3 in this study.

3.4.3 Sensitivity of PV Deployment to Primary

The lateral fuse was found to limit the PV that could be deployed to Lateral #3. A sensitivity analysis was performed to determine approximately how much PV could be installed before the lateral voltage exceeded 1.05 per-unit. Figure 30 shows the voltage profile of Lateral #3 with a significantly larger PV system installed.

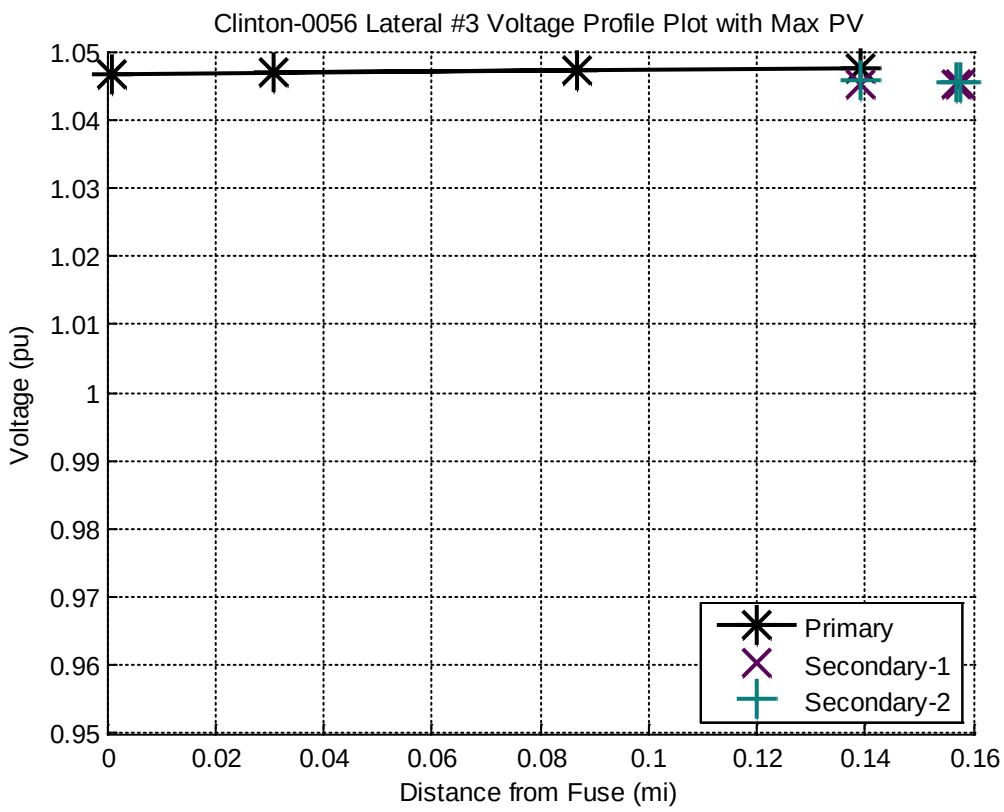

Figure 30. Lateral #3 Voltage Profile with 2500-kW of PV

It was found that, under the conditions of this study, Lateral #3 could accommodate an unrealistic level of PV before the lateral voltage exceeded 1.05 per-unit; in the plot above, 2.5-MW of PV was studied and the voltage did not exceed 1.05 per-unit.

3.4.4 240-V PV Deployment to Secondary

According to the guidelines developed in Section 2, the limiting factor for 240-V PV deployment to distribution secondary is the size of the distribution transformer. The guidelines state that 240-V PV is allowed up to a combined aggregate rating equal to the transformer rating. For a 10-kVA transformer, the distance from the transformer to the PV system is limited to 2000 feet for #2 AL Triplex conductors with an increase of 55% for 1/0 AL Triplex conductors.

The secondary studied on Lateral #3 was supplied by a 10-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 57.2 feet, which is less than the allowable 3100 feet. Figure 31 shows the voltage profile for Lateral #3 with 10-kW of 240-V PV installed on the secondary.

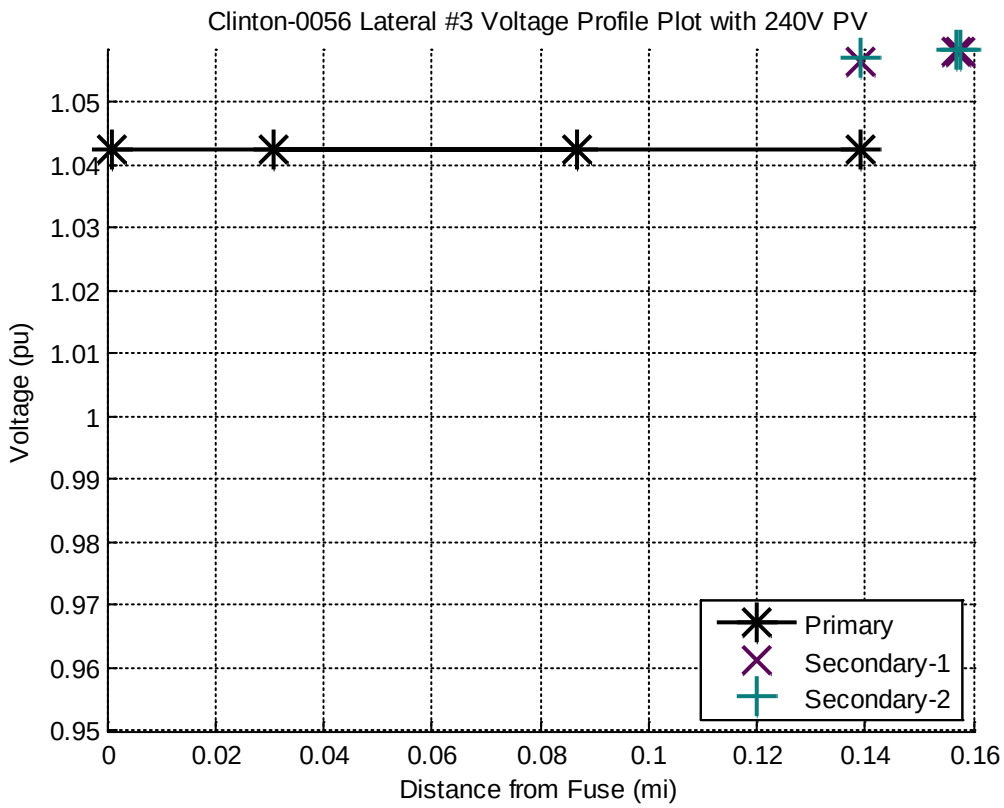

Figure 31. Lateral #3 Voltage Profile with 10-kW of 240-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by a 0.0161 per-unit. The voltage of Lateral #3 reached a maximum of 1.0586 per-unit in this study. The limits in Section 2 were developed by limiting the voltage rise caused by the introduction of PV. This was based on a desire to keep the voltage on the feeder below 1.05 per-unit, which in turn requires the assumption that the voltage at the head of the lateral would be close to 1.0 per-unit prior to the introduction of PV. This study suggests that limiting the voltage rise caused by the PV will not always be sufficient for all laterals.

3.4.5 120-V PV Deployment to Secondary

According to the guidelines developed in Section 2, 120-V PV deployment to a distribution secondary is limited by the size of the distribution transformer. For a 10-kVA transformer, the limit was 2.5-kVA. The distance from the transformer to the PV system is limited to 600 feet for #2 AL Triplex conductors with an increase of 20% for 1/0 AL Triplex conductors.

The secondary studied on Lateral #3 was supplied by a 10-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 57.2 feet which is less than the allowable 720 feet Figure 32 shows the voltage profile for Lateral #3 with 2.5-kW of 120-V PV installed on the secondary.

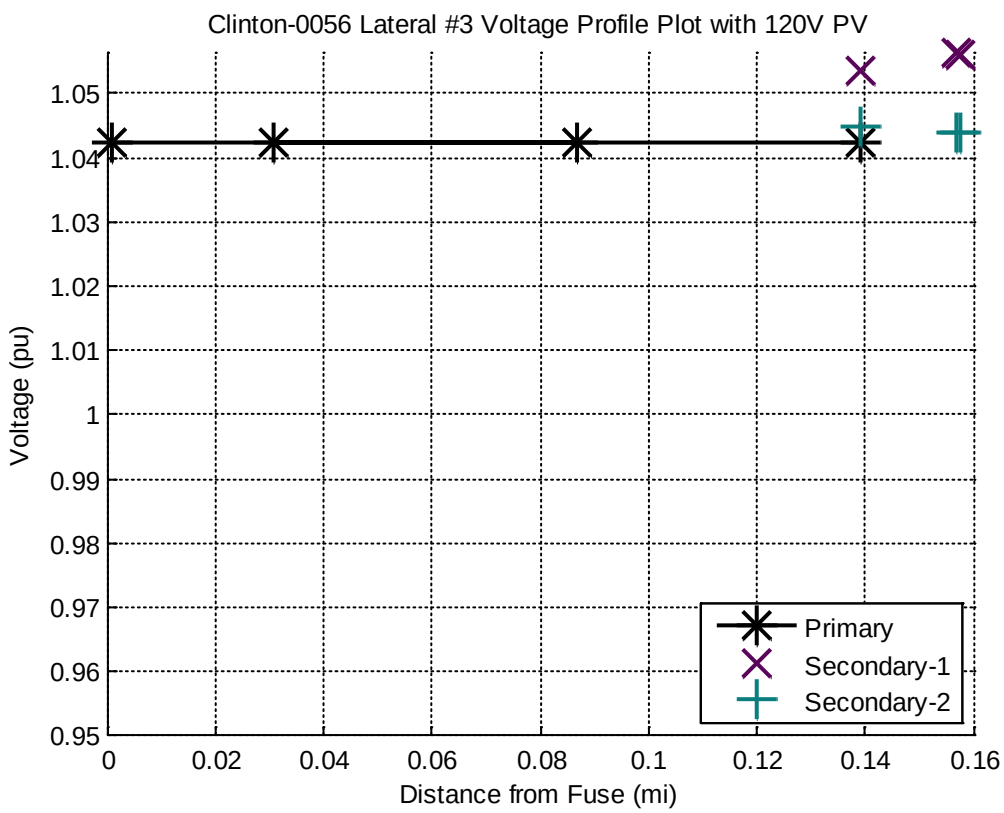

Figure 32. Lateral #3 Voltage Profile with 2.5-kW of 120-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by 0.0138 per-unit. The secondary imbalance was as high as 1.23%. The voltage of Lateral #3 reached a maximum of 1.0562 per-unit in this study. The limits of Section 2 were developed by limiting the voltage rise and the secondary imbalance caused by the introduction of PV. This was based on a desire to keep the voltage on the feeder below 1.05 per-unit, and requires the assumption that the voltage at the head of the lateral would be close to 1.0 per-unit prior to the introduction of PV. This study suggests that limiting the voltage rise and secondary imbalance caused by the PV will not always be sufficient for all laterals.

3.5 LATERAL #4

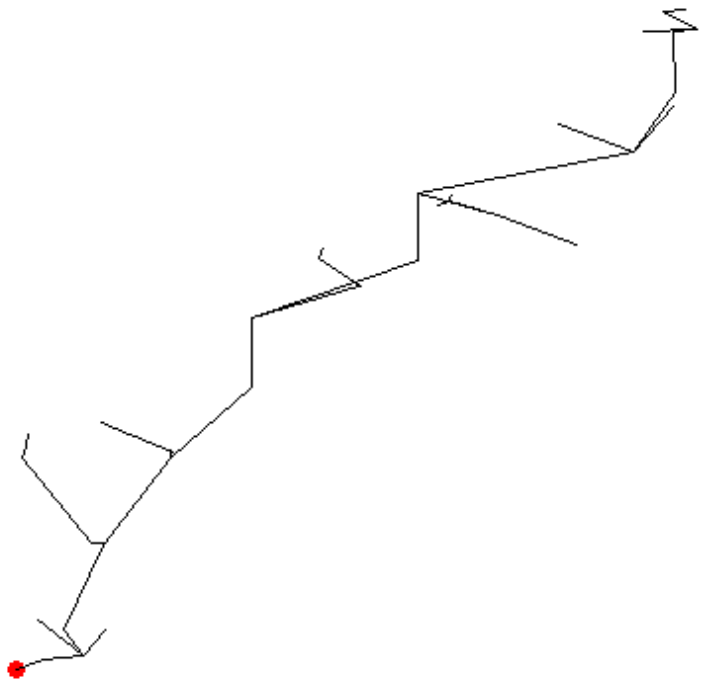

Figure 33. Lateral #4 Topology

Lateral #4 is located left of the center of Figure 11. It is protected by a 40-A fuse and is about 3.3 miles from the substation. Lateral #4 is an intermediate distance from the substation; it has a moderate Thevenin impedance. The lateral has the largest fuse and the highest load of the laterals studied in Section 3. The voltage at the head of the lateral is close to 1 per-unit. These and other characteristics are summarized in Table 7.

Table 7. Characterization of Lateral #4

#	Color	ph	Fuse	Conductor Type	Dist (mi)	P-typ (kW)	V-typ (pu)	Xth-calc (ohm)	Rth-calc (ohm)
4	Green	2	40-A	Mixed	3.262	22.1	0.992	2.63	1.53

Figure 34 shows the voltage profile of Lateral #4 under typical load conditions.

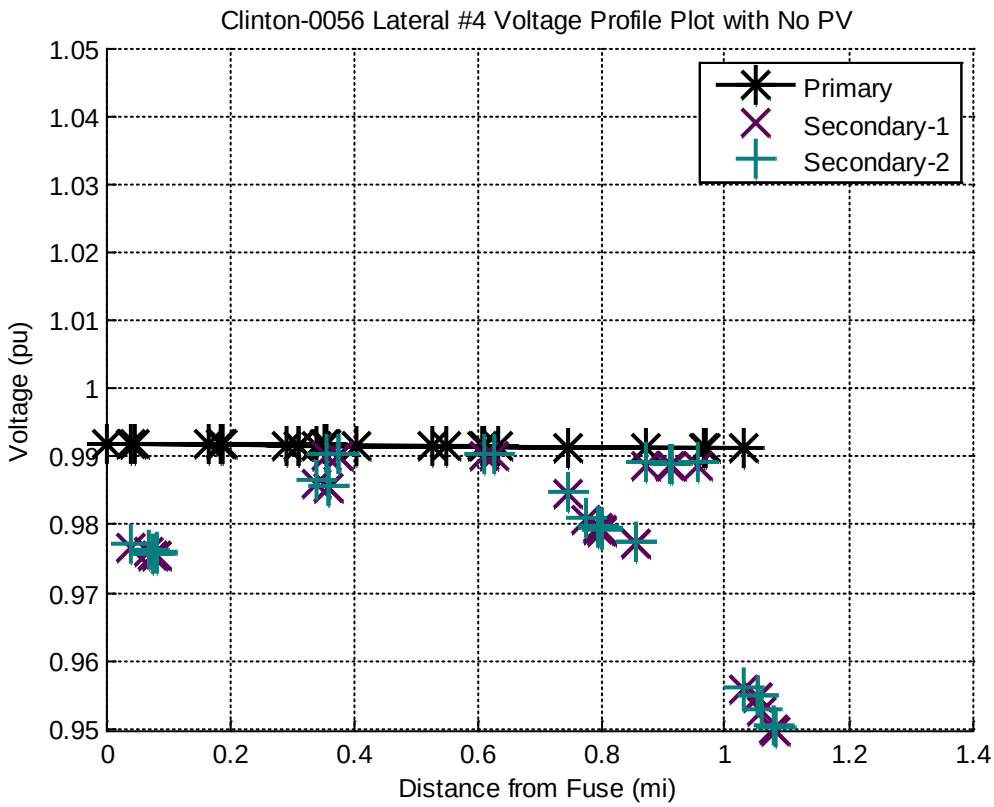

Figure 34. Lateral #4 Voltage Profile under Typical Load

3.5.1 Base Case for PV Analysis

Figure 35 shows the voltage profile for Lateral #4 under light load conditions. The voltage of the lateral is more than 0.05 per-unit higher than the typical load case and is much closer to the substation regulator set-point of 1.04 per-unit.

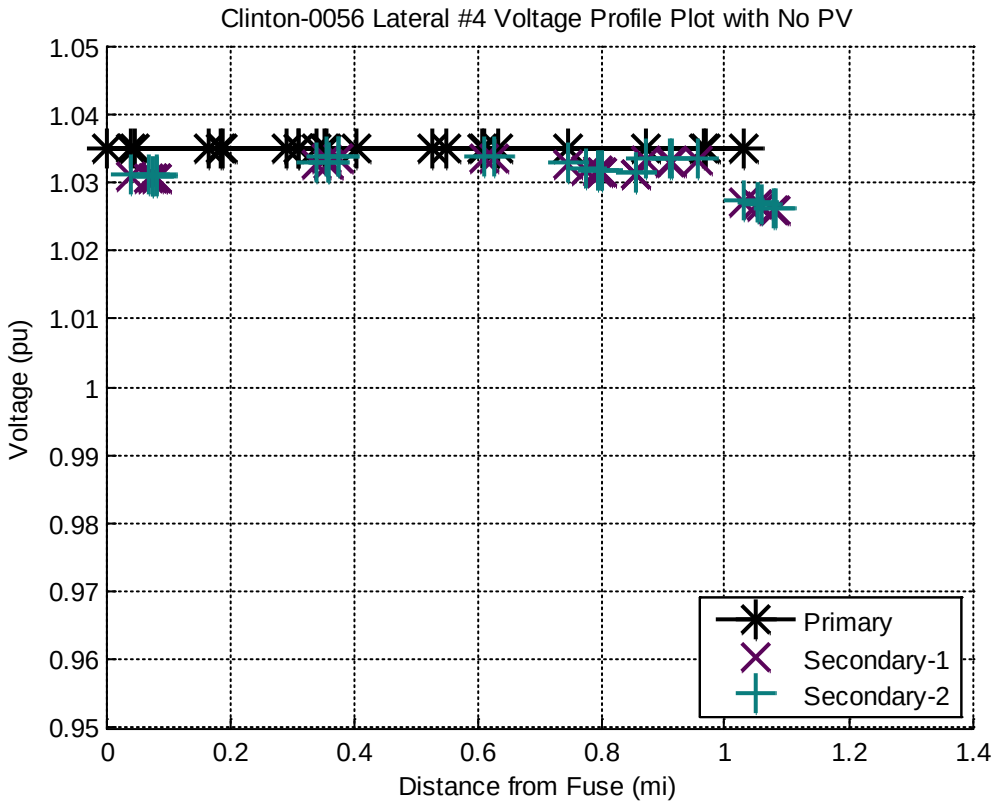

Figure 35. Lateral #4 Voltage Profile under Light Load

3.5.2 PV Deployment to Primary

According to the guidelines developed in Section 2, the limiting factor for PV deployment to a fused single-phase lateral is the size of the fuse. The combined fault current contribution from all PV systems on a lateral was not allowed to exceed the rating of the fuse. Lateral #2 is protected by a 40-A fuse.

The guidelines do not cover fuses larger than 25-A. The guideline is based on a comparison of the fuse rating to the fault current rating of the PV system, assuming a PV system fault current contribution of 1.2 per-unit.

$$I_{PV}^{fault} = \frac{S_{PV}}{V_{LN}} * 1.2 \leq I_{fuse} \tag{7}$$

Rearranging the equation above, the estimated maximum PV rating can be obtained.

$$S_{PV}^{max} = V_{LN} * I_{fuse} = \frac{12.47\ kV}{\sqrt{3}} * \frac{40\ A}{1.2} = 240\ kVA \tag{8}$$

A load-flow solution was performed with a 240-kVA PV system operating at unity power factor installed on Lateral #4. In the case of Lateral #4, there is an additional 10-A fuse at the end of the line; the PV was placed at the farthest node from the head of the lateral before the smaller fuse. Figure 36 shows the voltage profile of Lateral #4 for the simulation described.

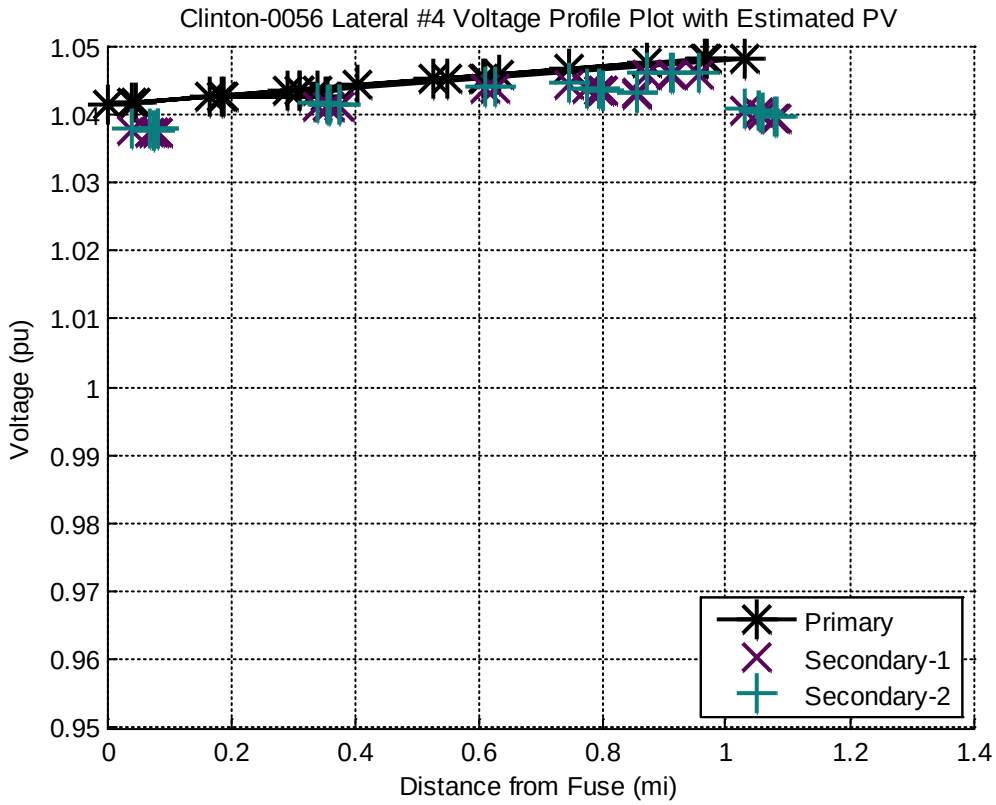

Figure 36. Lateral #4 Voltage Profile with 240-kW of PV

As seen above, the installation of 240-kW of PV has some impact on the voltage profile of Lateral #4. The voltage at the end of the lateral is higher than the voltage at the head of the lateral. The maximum voltage on the lateral with the PV installation is 1.0482 per-unit compared to 1.0350 per-unit with no PV. This is a difference of 0.0132 per-unit. The limit established in Section 2 for PV on the primary of a single-phase lateral was found to be valid for Lateral #4 in this study.

3.5.3 Sensitivity of PV Deployment to Primary

The lateral fuse was found to limit the PV that could be deployed to Lateral #4. A sensitivity analysis was performed to determine approximately how much PV could be installed before the lateral voltage exceeded 1.05 per-unit. Figure 37 shows the voltage profile of Lateral #4 with a modestly larger PV system installed.

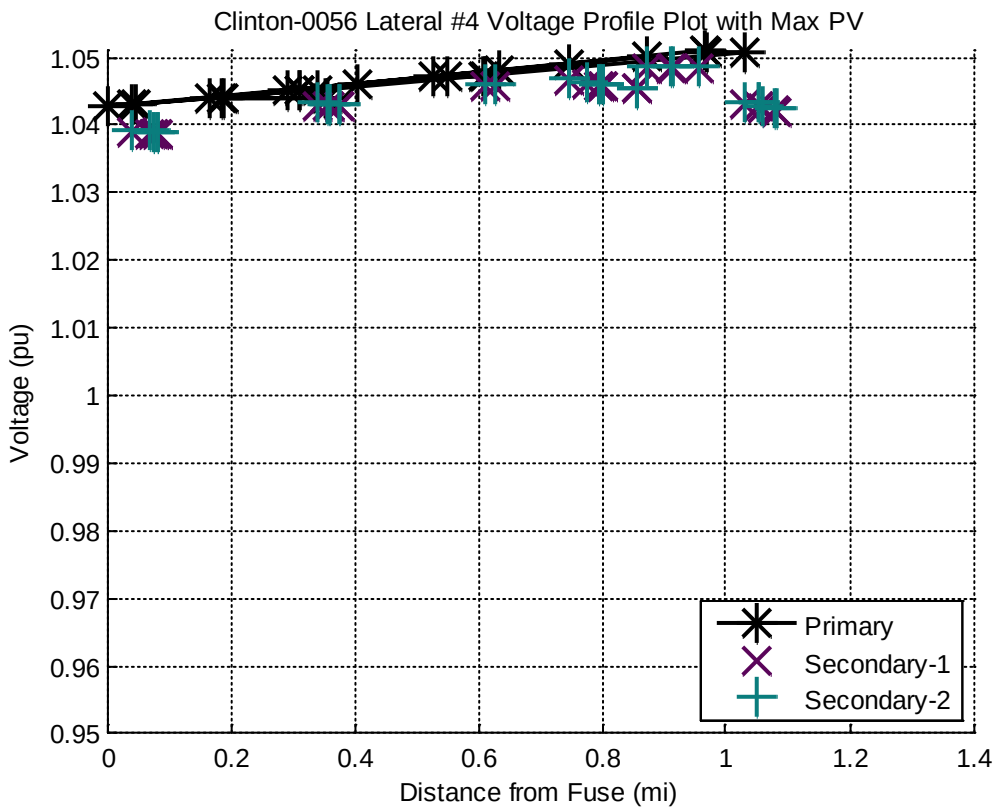

Figure 37. Lateral #4 Voltage Profile with 290-kW of PV

It was found that, under the conditions of this study, Lateral #4 could not accommodate 290-kW of PV without the voltage exceeding 1.05 per-unit. The margin between the rating of the lateral fuse and the allowable PV is smaller for Lateral #4 than for any of the other laterals

studied on this feeder. The larger fuse allows for a higher level of PV. In addition, the longer length of the feeder leads to more voltage rise over the length of the feeder. The guidelines developed in Section 2 do not cover laterals protected by fuses larger than 25-A. The results of this study suggest that caution should be used when extending principles of the Section 2 guidelines to larger laterals.

3.5.4 240-V PV Deployment to Secondary

According to the guidelines developed in Section 2, the limiting factor for 240-V PV deployment to distribution secondary is the size of the distribution transformer. The guidelines state that 240-V PV is allowed up to a combined aggregate rating equal to the transformer rating. For a 50-kVA transformer, the distance from the transformer to the PV system is limited to 400 feet for #2 AL Triplex conductors with an increase of 55% for 1/0 AL Triplex conductors.

The secondary studied on Lateral #4 was supplied by a 50-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 159 feet which is less than the allowable 620 feet. Figure 38 shows the voltage profile for Lateral #4 with 50-kW of 240-V PV installed on the secondary.

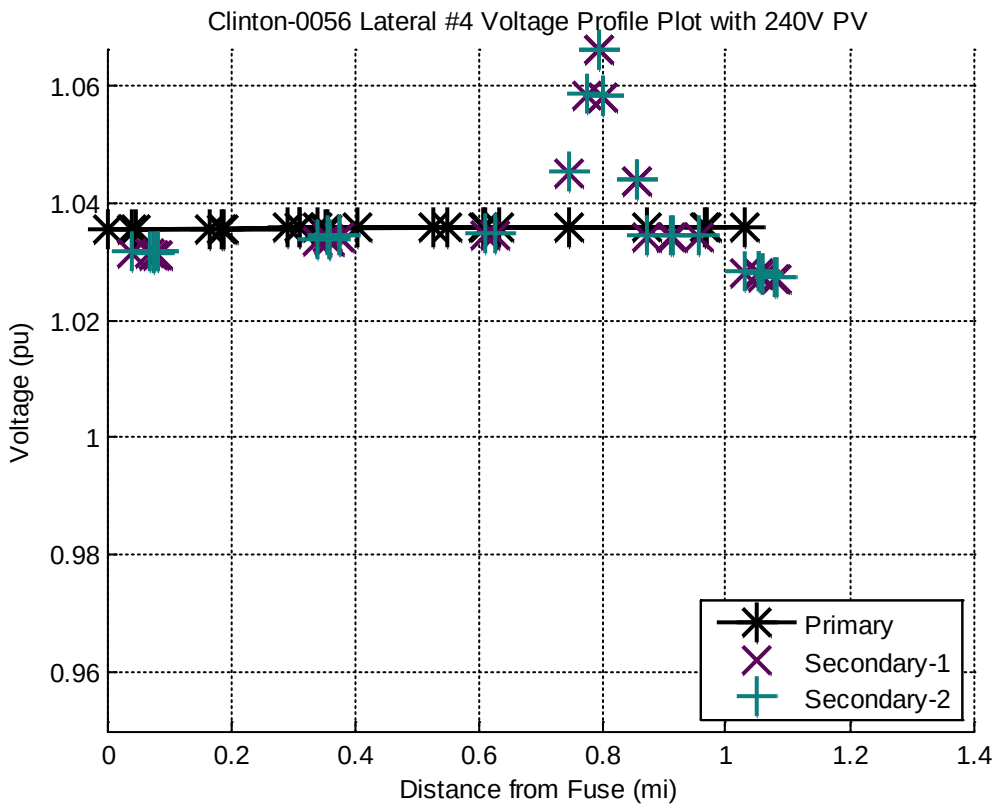

Figure 38. Lateral #4 Voltage Profile with 50-kW of 240-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by 0.0303 per-unit. The voltage of Lateral #4 reached a maximum of 1.0663 per-unit in this study. The limits in Section 2 were developed by limiting the voltage rise caused by the introduction of PV. This was based on a desire to keep the voltage on the feeder below 1.05 per-unit, which in turn requires the assumption that the voltage at the head of the lateral would be close to 1.0 per-unit prior to the introduction of PV. This study suggests that limiting the voltage rise caused by the PV will not always be sufficient for all laterals.

3.5.5 120-V PV Deployment to Secondary

According to the guidelines developed in Section 2, 120-V PV deployment to a distribution secondary is limited by the size of the distribution transformer. For a 50-kVA transformer, the limit was 13-kVA. The distance from the transformer to the PV system is limited to 105 feet. For #2 AL Triplex conductors with an increase of 20% for 1/0 AL Triplex conductors.

The secondary studied on Lateral #4 was supplied by a 50-kVA transformer. The construction of the secondary is 1/0 AL Triplex. The distance from the transformer to the PV site is 159 feet which is more than the allowable 126 feet. Figure 39 shows the voltage profile for Lateral #4 with 13-kW of 120-V PV installed on the secondary.

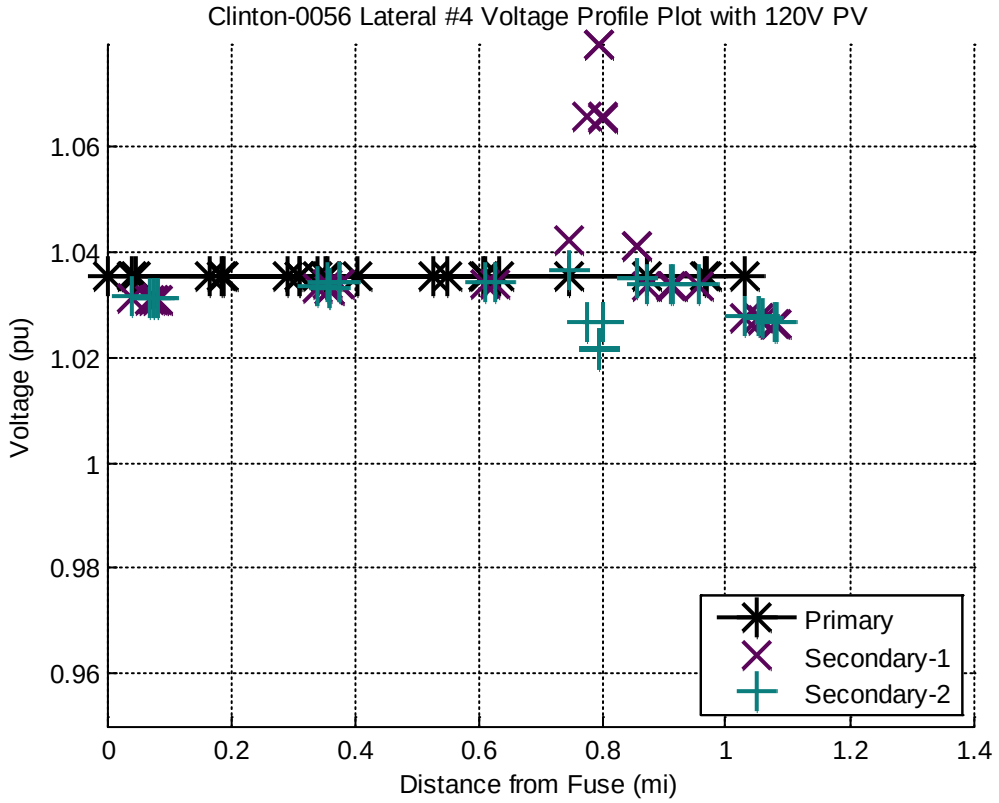

Figure 39. Lateral #4 Voltage Profile with 13-kW of 120-V PV

The maximum voltage of the secondary exceeded the maximum voltage of the primary by 0.0442 per-unit. The secondary imbalance was as high as 5.80%. The voltage of Lateral #4 reached a maximum of 1.0796 per-unit in this study. In this case, the PV system was located farther from the distribution transformer than recommended by the Section 2 guidelines so undesirable results can be anticipated.

3.6 CONCLUSIONS

In this section, general conclusions are drawn from the results of studies on each of the four laterals. The results of these studies are intended to provide insight into the guidelines developed in Section 2. The results depend not only on the specific characteristics of the lateral being studied, but also on choices related to modeling the feeder at large; as such, they cannot be generalized for all laterals on all feeders. For analysis related to a specific study, please see the section corresponding to that study.

3.6.1 Deployment to Primaries of Single-Phase Laterals

Some high-level results of each of the four studies of deployment of hypothetical PV systems to primaries of single-phase laterals are summarized in Table 8. In each case, a hypothetical PV system was selected according to the guidelines developed in Section 2 and the impacts were studied using the system model.

Table 8. PV Deployment to Primary Study Results

#	Color	Lateral Characteristics					Study Parameters and Results		
		ph	Fuse	Dist (mi)	P-typ (kW)	V-typ (pu)	PV Size (kW)	V-max (pu)	Δ[V-max] (pu)
1	Red	1	10-A	5.87	1.450	0.980	60	1.035	0.0027
2	Blue	2	25-A	6.67	6.879	0.980	150	1.04	0.0083
3	Pink	3	25-A	0.869	0.9573	1.03	150	1.04	0.0016
4	Green	2	40-A	3.26	22.2	0.992	240	1.05	0.0132

In each case, the size of the PV system was limited according the size of the fuse. For the fuse sizes analyzed in Section 2 (10-A and 25-A), the impact on the system voltages was minimal. The largest impact was seen on the lateral with the largest fuse (40-A). The larger size of the PV system and the longer length of the lateral contributed to the higher voltage rise.

The results of these studies suggest that the guidelines developed in Section 2 for PV deployment to primaries of single-phase laterals are robust for fuse sizes included in the guidelines (up to 25-A). As the size of the fuse increases beyond 25-A, the voltage rise caused by the PV system may need to be considered alongside the fuse size when determining limits.

3.6.2 Sensitivity of PV Deployment to Secondaries

The analysis in this section was performed to examine conclusion in Section 2 that PV is limited by fuse size on single phase laterals. It was not intended to suggest that fuse sizes should be increased to accommodate additional PV. Protection devices are critical for ensuring distribution system reliability and fuse size cannot be increased without carefully considering all impacts on protection and coordination.

Some high-level results of each of the four studies of sensitivity studies of hypothetical PV systems connected to laterals without regard for protection devices are summarized in Table 9. In each case, the size of a hypothetical PV system increased in an attempt to produce a maximum voltage of 1.05 per-unit.

Table 9. Sensitivity of PV Deployment to Secondaries Results

		Lateral Characteristics					Study Parameters and Results
#	Color	ph	Fuse	Dist (mi)	P-typ (kW)	V-typ (pu)	Maximum PV Size (kW)
1	Red	1	10-A	5.87	1.450	0.980	400
2	Blue	2	25-A	6.67	6.879	0.980	300
3	Pink	3	25-A	0.869	0.9573	1.03	> 2500
4	Green	2	40-A	3.26	22.2	0.992	240*

* The limit considering protection was found to be close to the limit neglecting protection

For the two smaller laterals more than five miles from the substation (Laterals #1 and #2), there was a margin of at least 150-kW between the fused limit and the unfused limit. For the smaller system close to the substation (Lateral #3), the voltage rise limit was high enough to tolerate sufficient PV to power more than half of the feeder at typical load. For the larger lateral (Lateral #4), the fused limit was close to the unfused limit. Consistent with the studies above, the results of these studies suggest that the guidelines developed in section 2 for PV deployment to primaries of single-phase laterals are robust for fuse sizes included in the guidelines (up to 25-A). For laterals with fuses larger than 25-A, the voltage rise caused by the PV system may need to be considered alongside the fuse size when determining limits.

3.6.3 240-V PV Deployment to Secondaries of Single-Phase Laterals

Some high-level results of each of the four studies of deployment of hypothetical PV 240-V systems to secondaries of single-phase laterals are summarized in Table 10. In each case, a hypothetical PV system was selected according to the guidelines developed in Section 2 and the impacts were studied using the system model.

Table 10. 240-V PV Deployment to Secondary Study Results

	Lateral Characteristics		Secondary Characteristics		Study Parameters and Results		
#	Dist (mi)	V-typ (pu)	Xfmr (kVA)	Len (ft)	PV Size (kW)	V-max (pu)	V”-V’ (pu)*
1	5.87	0.980	25	53.3	25	1.048	0.016
2	6.67	0.980	15	215	15	1.055	0.022
3	0.869	1.03	10	57.2	10	1.059	0.016
4	3.26	0.992	50	159	50	1.066	0.030

* V”-V’ refers to the maximum secondary voltage minus the maximum primary voltage

The maximum lateral voltage with PV exceeded 1.05 per-unit in three of these cases. This appears to be due to the relatively high voltage of the lateral in the low-load condition (despite a voltage near 1.0 per-unit for a typical load condition) prior to the introduction of the PV system. The guidelines in Section 2 were developed assuming that the lateral head voltage would be near 1.0 per-unit prior to the introduction of PV. Because most feeders are not designed to control voltage in this way for all load levels, care should be taken when using these guidelines to consider the implications of a voltage rise up to 0.05 per-unit.

3.6.4 120-V PV Deployment to Secondaries of Single-Phase Laterals

Some high-level results of each of the four studies of deployment of hypothetical PV systems to primaries of single-phase laterals are summarized in Table 11. In each case, a hypothetical PV system was selected according to the guidelines developed in Section 2 and the impacts were studied using the system model.

Table 11. 120-V PV Deployment to Secondary Study Results

#	Lateral Characteristics			Secondary Characteristics	Study Parameters and Results			
	Dist (mi)	V-typ (pu)	Xfmr (kVA)	Len (ft)	PV Size (kW)	V-max (pu)	V”-V’ (pu)*	Secondary Imbalance
1	5.87	0.980	25	53.3	6.5	1.0487	0.0167	1.67%
2	6.67	0.980	15	215	3.8	1.0589	0.0252	1.23%
3	0.869	1.03	10	57.2	2.5	1.0562	0.0138	1.23%
4	3.26	0.992	50	159**	13	1.0796	0.0442	5.80%

* V”-V’ refers to the maximum secondary voltage minus the maximum primary voltage
** This system was placed beyond the recommended distance limit from the transformer

Similar to the results of the 240-V PV studies, the maximum lateral voltage with PV exceeded 1.05 per-unit in all four cases. Again, care should be taken when using these guidelines to consider the implications of a voltage rise up to 0.05 per-unit.

3.6.5 Result Dependence on Initial Lateral Voltage

The guidelines in section 2 were developed using an assumption that the voltage at the head of the lateral or secondary would be close to 1.0 per-unit prior to the introduction of PV. The voltage of any node on a distribution system changes over time depending on load levels throughout the system as well as the settings and states of voltage regulators and capacitors. In section 3, several cases were examined for which the low load voltage was above 1.0 per-unit. When voltage rise limited PV deployment, systems sized according to the guidelines in section 2 could cause the voltage to rise above 1.05 per-unit. The results in section 3 suggest that limiting the voltage rise caused by the PV will not always be sufficient for all laterals.

APPENDIX

CONVERSION OF GIS DATA TO OPENDSS MODELS

The Electric Power Distribution Modeling and Simulation for Feeder Analytics and Distributed Energy Resource Integration (Feeder Analytics Project) is a research project collaboration between FirstEnergy and the University of Pittsburgh with the purpose of creating new tools and concepts for the advancement of distribution feeder analytics. Specifically, the work developed advanced analytical applications that will help FirstEnergy analyze and integrate load, energy storage and distributed generation onto the electric distribution system [20].

GIS data was provided by FirstEnergy to the University of Pittsburgh in a comma delimited text file. Most of the information required to model a distribution system is contained in these text files but OpenDSS is not able to read the text files directly. The interpretation and parsing required to convert the GIS data into OpenDSS code is accomplished using Perl scripts. Other inputs are entered manually either using the OpenDSS scripted language or, using a graphical user interface. In addition to the GIS extract file, FirstEnergy provided the University of Pittsburgh with an equipment catalog, which includes component parameters such as real and reactive loss identified by a descriptive component name.

A.1 CONNECTIVITY

The GIS comma delimited file includes two main parts: a connectivity table and several component data tables. The connectivity table indicates which nodes each component is connected to and, by extension, which components are connected to each other. The connectivity table is cross-referenced with the data tables discussed in later subsections. Below is a list of the relevant fields in the connectivity table:

- DB_FEAT_NUM – used to correlate the connectivity table with the component data tables
- FROM_NODE – BUS1 of the component will be connected to this node
- TO_NODE – BUS2 of the component will be connected to this node

Note: the GIS fields listed in this table and throughout this section include only the fields used directly for OpenDSS model creation. In all cases, additional fields are present in the GIS data, which are not used to generated OpenDSS code.

A.2 NODE COORDINATES

In addition to the connectivity and functional parameters discussed throughout this section, each component data table includes the latitude and longitude of the component. These coordinates are compiled into a node coordinates file, which is read into the OpenDSS model. The node coordinates file allows distribution systems to be plotted geographically.

For small components with a single latitude and longitude such as transformers, fuses, capacitors and service points, the latitude and longitude are assigned to both nodes (from node and to node) associated with that component.

Components with long length, such as primary and secondary conductors, have minimum and maximum latitude and longitude specifications. These minimum and maximum values do not necessarily correspond to conductor endpoints, which means the specified coordinates cannot be directly associated with either node. To determine the appropriate node assignment, an algorithm traces through the connectivity table until a small component is found. The latitude and longitude matching the small component are assigned to the appropriate conductor node and the remaining latitude and longitude are assigned to the other conductor node. The algorithm traces back to the original line, specifying one node at a time in this manner until all nodes are specified.

The distribution system layout can be reasonably approximated using this method. Inaccuracy is introduced when a conductor has curvature such that one of the maximum or minimum coordinates corresponds to a point on an arc rather than an endpoint. In addition, the latitude and longitude supplied with small components are associated with the physical component, rather than the terminal or node.

A.3 PRIMARY CONDUCTORS

The GIS primary conductor table contains conductor material information as well as an overhead/underground flag, length and phasing information. The following fields are used to generate OpenDSS code:

- DB_FEAT_NUM – used to correlate this component with the connectivity table
- COND_QTY – determines the number of entries in the “wires” vector
- COND_SIZE – part of individual wire definition
- COND_TYPE – part of individual wire definition
- NEUTRAL_WIRE_SIZE – part of individual wire definition
- NEUTRAL_WIRE_TYPE – part of individual wire definition
- OH_UG_CD – used to determine whether the wire is overhead or underground
- LENGTH – multiplier for the line parameters, in miles
- PHASING – used to determine the conductor phase or phases

The material type data (conductor quantity as well as conductor and neutral size and type) are used to reference the equipment catalog, which contains line constant parameters per-unit length. When combined with the GIS length parameter, line constants can be determined for each primary conductor.

Below is the Perl code for printing a line of OpenDSS code:

```
print $dssfile "New line.Line$rawname "."bus1=$bus1 bus2=$bus2 spacing=$spacing wires=$wires"." Units=mi Length=$Length \t// $tablename\n";
```

Below is a line of OpenDSS code generated from the Perl code above:

```
New line.Line6195656346 bus1=6195656348.1 bus2=6195656347.1 spacing=1_15KV wires=[1/0ACSR 1/0ACSR] Units=mi Length=0.0305699478011314 //
CONDUCTOR - PRIMARY
```

The busses are determined from the corresponding entry in the connectivity table. The “spacing” and “wires” parameters in OpenDSS reference equipment catalog entries and are used for creating line constant parameters.

A.4 DISTRIBUTION TRANSFORMERS

The GIS data processed during this project does not contain detailed data on distribution transformers. The primary and secondary voltages are not reliably specified and there is often insufficient information to link the transformer uniquely to an entry in the equipment catalog.

In order to address the lack of explicit transformer data, it was assumed that for all distribution transformers, the primary voltage is the distribution system voltage and the secondary voltage is the customer voltage, i.e. there are no intermediate voltages. The secondary voltage is determined based on guidance from FirstEnergy that in their systems, it is reasonably likely that distribution transformers strictly larger than 500 KVA provide a secondary voltage of 480/277 V and those smaller than 500 KVA provide a secondary voltage of 208/120 V. Single-phase transformers are assumed to have a split-phase secondary.

Because it is not possible to robustly determine the real and reactive loss parameters either directly from the GIS data or by looking up an entry in the equipment catalog, it is necessary to approximate transformer loss. The following look-up tables were supplied by The University of Pittsburgh, sourced from a Westinghouse handbook.

Single Phase Transformer Parameters:

Size	%LoadLoss	Xhl	%NoLoadLoss	%imag
5 kVA	2.10	1.53	0.90	3.38
10 kVA	1.90	1.30	0.68	2.92
15 kVA	1.70	1.47	0.60	2.53
25 kVA	1.60	1.51	0.52	1.93
38 kVA	1.45	1.65	0.47	1.74
50 kVA	1.30	1.77	0.45	1.54

75 kVA	1.25	1.69	0.42	1.49
100 kVA	1.20	2.19	0.40	1.45
167 kVA	1.15	2.77	0.38	1.66
250 kVA	1.10	3.85	0.36	1.81
333 kVA	1.00	4.90	0.34	1.97
500 kVA	1.00	4.90	0.29	1.98

Three Phase Transformer Parameters:

Size	%LoadLoss	Xhl	%NoLoadLoss	%imag
30	1.77	1.90	0.79	4.43
45	1.75	2.12	0.70	3.94
75	1.60	2.42	0.63	3.24
113	1.45	2.85	0.59	2.99
150	1.30	3.25	0.54	2.75
225	1.30	3.52	0.50	2.50
300	1.30	4.83	0.46	2.25
500	1.10	4.88	0.45	2.26
750	0.97	5.11	0.44	1.89
1000	0.85	5.69	0.43	1.65
1500	0.78	5.70	0.39	1.51
2000	0.72	5.70	0.36	1.39
2500	0.70	5.71	0.35	1.36
3750	0.62	5.72	0.31	1.20
5000	0.55	5.72	0.28	1.07

Note: For transformer sizes that are not included in the table above, a linear interpolation or extrapolation is performed for each of the four variables above.

The following GIS fields are used to create OpenDSS code:

- DB_FEAT_NUM – Used to correlate this component with the connectivity table
- Site_No – Used to correlate service points with transformers
- KVA_1 – Used to determine the transformer size
- KVA_2 – Used to determine the transformer size
- KVA_3 – Used to determine the transformer size
- PHASE_INST_ON_1 – Used to determine the number of phases
- PHASE_INST_ON_2 – Used to determine the number of phases
- PHASE_INST_ON_3– Used to determine the number of phases

GIS data is used only to determine the size and number of phases of the transformer in addition to its connectivity.

Below is the Perl code for printing a line of OpenDSS code:

```
print $dssfile "New Transformer.Transformer$rawname "."buses=[$bus1, $bus2] windings=2, phases=$phases "."kvas=($KVA $KVA) kvs=($primKV $secKV) "."conns=(wye,wye) $params \t// Transformer\n";
```

Below is a line of OpenDSS code generated from the Perl code above:

```
New Transformer.Transformer516143834 buses=[511410972, 518988987] windings=2, phases=3 kvas=(500 500) kvs=(12.47 0.208) conns=(wye,wye) xhl=4.88 %LoadLoss=1.10 %NoLoadLoss=0.45 %imag=2.26 // Transformer
```

The busses are determined from the connectivity table. The number of windings and connection type (wye-wye) are common settings for this project. The number of phases and

primary and secondary kVA are derived from the GIS data. The other parameters are determined according to the discussion and tables above.

A.5 SECONDARY AND SERVICE CONDUCTORS

The GIS data for some distribution systems studied in this project contains varying levels of detail in the secondary. Some systems have most or all secondary and service conductors mapped, while others map service points and other secondary components directly to the secondary side of the distribution transformer.

The specification of secondary and service conductors is, in general, similar to that of primary conductors; however, the equipment catalog does not have suitable entries for the secondary conductors. Therefore, the following standard 1/0 triplex (for GIS overhead triplex secondary), 1/0 open wire (for GIS overhead non-triplex secondary) and 1/0 underground cable (for GIS underground secondary) conductor definitions are used according to available GIS information:

- "new WireData.1/0 Runits=kft radunits=in GMRunits=in diam=0.368 GMRac=0.13351 Rac=0.1857 normamps=120\n".
- "new LineSpacing.1/0_TriplexFN nconds=2 nphases=1 units=in h=[240.3516,240.3516,240] x=[-0.244,0.244]\n".
- "new LineSpacing.openwire nconds=2 nphases=1 units=in h=[246,234] x=[0,0]\n".
- "new CNData.CN_1/0AL NormAmps=265 DIAM=0.368 GMRac=0.13320 Rac=0.9580000 Runits=mi Radunits=in gmrunits=in\n"."~ EpsR=2.3

Ins=0.345 DiaIns=1.0625 DiaCable=1.29 k=6 DiaStrand=0.0641 GmrStrand=0.02496 Rstrand=14.8722\n".

- "new LineSpacing.ugsec nconds=2 nphases=1 units=ft x=[0.0 0.0833] h=[-4 -4]\n";

The first three items apply to overhead secondary conductors. For overhead conductors specified as triplex, the “triplex” line spacing is used. For other overhead conductors, the “openwire” spacing is used.

The last two items apply to underground secondary conductors; together these items allow an underground secondary cable to be specified.

The following GIS fields are used to create OpenDSS code:

- DB_FEAT_NUM – Used to correlate this component with the connectivity table
- COND_DESC – Used for overhead conductors to determine triplex or open spacing
- OH_UG_CD – Used to determine whether the conductor is overhead or underground
- LENGTH – multiplier for the line parameters; in miles

Note: The phasing is not available in the GIS data for secondary conductors. Because of this, split-phase secondaries are modeled on the “secondary-1” and “secondary-2” phases in OpenDSS.

Below is the Perl code for printing a line of OpenDSS code:

```
print $dssfile "New line.Line$rawname "."bus1=$bus1.1.2.0 bus2=$bus2.1.2.0 spacing=1/0_TriplexFN wires=[1/0 1/0 1/0]"." Units=mi Length=$Length \t// $tablename\n";
```

Below is a line of OpenDSS code generated from the Perl code above:

New line.Line6198219716 bus1=6195707383.1.2.0 bus2=6195708836.1.2.0 spacing=1/0_TriplexFN wires=[1/0 1/0 1/0] Units=mi Length=0.0101760960031916 // CONDUCTOR - SECONDARY & SERVICE

The busses are determined from the connectivity table. The spacing and wires are determined as discussed above. Length is determined from the GIS data.

A.6 FUSES, RECLOSERS, SWITCHES, SECTIONALIZERS, ELBOWS

Several items are modeled in OpenDSS as short, lossless lines. This was determined to be appropriate for components that are physically short (conductors) and that generally contribute a negligible amount of loss to the system. These component types include fuses, reclosers, switches, sectionalizers, and elbows.

OpenDSS supports this functionality with the keyword “switch.” If a component definition includes the flag “switch=yes” the component will behave as a short component with negligible loss.

An OpenDSS “switch” can be opened using the keyword “open.” This is appropriate for several of the components discussed in this section, which may open either as part of a protection scheme or in order to reconfigure the distribution system.

The GIS fields available for each of the components discussed in this section are different; however, the fields that are used to generate OpenDSS code are functionally similar. The following GIS fields are used to create OpenDSS code for a fuse:

- DB_FEAT_NUM – Used to correlate this component with the connectivity table

- CURRENT_STATUS_1 – Used to determine whether the component is “open”
- CURRENT_STATUS_2 – Used to determine whether the component is “open”
- CURRENT_STATUS_3 – Used to determine whether the component is “open”
- PHASE_INST_ON_1 – Used to determine component phase or phases
- PHASE_INST_ON_2 – Used to determine component phase or phases
- PHASE_INST_ON_3 – Used to determine component phase or phases

Below is the Perl code for printing a line of OpenDSS code for a fuse:

```
print $dssfile "New line.Fuse$rawname "."bus1=$bus1 bus2=$bus2 phases=$phases Switch=yes "."\t// $tablename\n";
```

Below is the Perl code for printing a line of OpenDSS code to open a fuse:

```
print $dssfile "open line.Fuse$rawname\n"
```

Below are two lines of OpenDSS code generated from the Perl code above:

```
New line.Fuse5112530447 bus1=51102758.1 bus2=511410815.1 phases=1 Switch=yes
        // Fuses
open line.Fuse5112530447
```

A.7 CAPACITORS AND REGULATORS

Some components, such as capacitors and regulators, can be controlled based on parameters such as the voltage at a specified node. For controlled components, the component and the control scheme can be specified separately. Controlled components (except for the substation voltage regulator) are specified according to GIS. The substation voltage regulator, capacitor bank and line voltage regulator control schemes are specified manually.

The following GIS fields are used to create OpenDSS code for a capacitor:

- DB_FEAT_NUM – Used to correlate this component with the connectivity table
- Bank_Kvar – Indicates the size of the capacitor bank
- Phase_Inst_On_1 – Used to determine the capacitor bank phasing
- Phase_Inst_On_2 – Used to determine the capacitor bank phasing
- Phase_Inst_On_3 – Used to determine the capacitor bank phasing

Note: additional parameters are included in the GIS data may someday be used to partially automate the creation of capacitor controls.

Below is the Perl code printing a line of OpenDSS code:

```
print $dssfile "New capacitor.Cap$rawname "."bus1=$bus1 kvar=$kvar kv=$kv \t// Capacitor\n";
```

Below is a line of OpenDSS code generated from the Perl code above:

```
New capacitor.CapBT1646ETN bus1=511410978 kvar=600 kv=12.47 // Capacitor
```

The bus is determined from the connectivity table; capacitors are assumed to be connected in a shunt configuration. The size is determined from the GIS data and the voltage is assumed to be the distribution system voltage.

A.8 SERVICE POINTS

Service points are the connection points for customer loads and distributed energy resources. In the GIS data used for this project, service points have two upstream links to the distribution system. The first link is the connectivity table, which specifies a “from” node for service points as it does for other interconnected components. The second upstream link to the distribution

system is a direct reference to the distribution transformer. In some cases, the two upstream links will point to the same location. That is, the service point will be connected directly to the transformer in the connectivity table.

The upstream connection node for a service point depends on the phasing of the associated transformer. The phasing of secondary and service conductors is not available in the GIS. This presents a complication for three-phase transformers, which may feed multiple single phase laterals or three-phase loads.

All service points associated with a three-phase distribution transformer are connected directly to that transformer in the OpenDSS model. Service points associated with single phase transformers are connected to the node specified in the connectivity table, which should be a service conductor if the distribution secondary if it is mapped in GIS or the distribution transformer if the distribution secondary is not mapped in GIS.

The following GIS fields are used to create OpenDSS code:

- DB_FEAT_NUM – Used to correlate this component with the connectivity table
- XFMR_SITE_NO – Used to determine the number of phases based on the transformer phasing; also used to determine which upstream connection point will be used

Below is a line of OpenDSS used to describe a service point:

New line.servpt5113850289 bus1=518989073 bus2=5124029603 phases=3 Switch=yes

A.9 CUSTOMER LOADS

Customer loads are connected to a service point on the distribution system secondary. Loads can be allocated proportionately according to a specified total feeder load. The total feeder load can be specified as a time-varying load shape, which will in turn cause each load to vary in time.

The following GIS fields are used to create OpenDSS code:

- PREMISE_NO – Used to determine the associated service point
- DEM_SUMMER_ONPK – Used to determine the size of the load

Below is a line of OpenDSS used to describe a load:

New load.loadS27803605 bus1=5124292426.1 phases=1 kv=.120 XfkVA=1 pf=0.9

The bus is determined based on the service point. The phasing and voltage are determined based on the distribution transformer associated with the service point. The load size is determined from the GIS. The project load power factor is fixed at 0.9 at this time.

Note: if loads are not “allocated,” each load will operate at its summer peak, creating an aggregate load that is larger than the maximum expected load.

A.10 DISTRIBUTED ENERGY RESOURCES

Distributed energy resources are connected to a service point on the distribution system secondary. Distributed energy resources can be assigned a time-varying profile, allowing the effects of sunlight for example to be studied.

The following GIS fields are used to create OpenDSS code:

- DB_FEAT_NUM – Used to correlate this component with the connectivity table

- GEN_SIZE – Used to determine the size of the DER
- NO_OF_PHASES – Used to determine the number of

Below is a line of OpenDSS used to describe a distributed energy resource:

New PVSystem.genBT1681ETN_5 phases=3 bus1=518988811 kV=0.208 kVA=42 pf=0.9

The bus is determined from the connectivity table. The voltage is determined based on the associated distribution transformer. The phasing and size are determined from the GIS component data table. The project load power factor is fixed at 0.9 at this time.

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