

Virginia Solar Pathways Project

Study 1: Distributed Solar Generation Integration and Best Practices Review

Final Report

Prepared for:

Dominion Virginia Power



Submitted by:

Navigant Consulting, Inc.
201 S. College Street, Suite 1350
Charlotte, NC 28244

+1.704.347.7735
navigant.com

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Content of Report

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ABSTRACT

This report documents Navigant Consulting, Inc.'s ("Navigant") evaluation of the impact of solar photovoltaic ("PV") capacity on Dominion Virginia Power's ("DVP" or "Dominion")¹ electric distribution system, which was commissioned to support the Virginia Solar Pathways Project ("SPP"), award No. DE-EE0006914. In partnership with the Department of Energy ("DOE"), the Virginia Solar Pathways Project aims to develop a collaborative, utility-administered solar strategy for the Commonwealth of Virginia. The goals of the VA SPP are (i) to integrate existing solar programs with new options appropriate for Virginia's policy environment and broader economic development objectives; (ii) to promote wider deployment of solar within a low retail electric rate environment; and (iii) to serve as a replicable model for use by other states with similar policy environments including, but not limited to, the entire Southeast region.

The project includes a core advisory team made up of a diverse group of stakeholders. The core advisory team consists of eight entities: Bay Electric Co., Inc., Virginia Department of Mines, Minerals, and Energy, Piedmont Environmental Council, Northern Virginia Community College, Old Dominion University Research Foundation, National Renewable Energy Laboratory, City of Virginia Beach, and Metro Washington Council of Governments. In addition to the core advisory team, DVP envisions providing additional opportunities to share information on project accomplishments with other interested stakeholders.

Navigant's study addresses two distinct topics relating to the integration of solar capacity: The first is a benchmarking and distribution analysis (Study 1: "Distributed Solar Generation Integration and Best Practices Review"); the second is an evaluation of impacts of solar on the interconnected high-voltage grid (Study 2: "Solar PV Generation System Integration Impacts"). This report addresses Study 1. A separate report addresses Study 2.

¹ Dominion is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 24,600 megawatts of generation, 12,400 miles of natural gas transmission, gathering, and storage pipeline, and 6,455 miles of electric transmission lines. While we refer to DVP throughout this report, the study does not include analysis of the T&D network resident within Dominion North Carolina Power.

LIST OF ACRONYMS

AC	Alternating Current
ADMS	Advanced Distribution Management System
DC	Direct Current
DG	Distributed Generation
DMS	Distribution Management System
DVP	Dominion Virginia Power
IEEE	Institute for Electrical and Electronics Engineers
LTC	Load Tap Changer
NEM	Net Energy Metering
OH	Overhead
UG	Underground
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
STATCOM	Distribution Static Var Compensator
USS	Utility-scale Solar
VA SCC	Virginia State Corporation Commission
VA SPP	Virginia Solar Pathways Project

GLOSSARY

Customer	Interconnecting customer versus DVP customers in service territory
Dynamic	A state variable that changes during small time steps. For the purposes of this report, this term applies to changes that occur in intervals of less than one minute.
Feeder	The distribution line coming from a substation and providing electricity to customers
Hosting Capacity	The amount of distributed generation that can be connected to a distribution feeder before upgrades to the feeder configuration are required.
IEEE 1547	A standard of the IEEE that provides a set of criteria to interconnect distributed generation to the grid and specify requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnected resources.
Interconnection Cost	A cost that is evaluated at the feeder level to achieve upgrades identified as necessary during the screening of a proposed interconnection resource.
Islanding	Refers to the ability of a distributed resource to energize sections of distribution circuits even after they are disconnected from its source of supply (e.g. after a contingency event). Islanding is a concern as the utility may not have control or monitoring of the distributed resource available to ensure safe operating conditions at the islanded point of the circuit.
Load Tap Changer	A mechanism that is associated with a power transformer to enable changes in the voltage output of the transformer.
Net Energy Metering	Net Energy Metering (NEM) is a utility billing practice for qualified renewable generators on the customer side of the meter. The practice allows qualified renewable generators to use the electric utility system to “bank” generation not used when generated and to receive a bill credit equal to the electricity generated, regardless of the time of the customer’s energy consumption. In Virginia, these distributed generation resources are 1 MW or below.
Overvoltage	Voltage that is sustained above the allowable safe operating threshold identified by the utility.
Radial Lines	Distribution lines where power flow is almost always in one direction, substation to customer load.
Secondary Network Systems	Distribution lines that operate in a grid or network configuration, offering very high level of redundancy and reliability
STATCOM Devices	A power electronics voltage-source converter that can act as either a source or sink of reactive AC power

Steady-state	An assumption that holds that the examined system is not changing with time (i.e. it has reached a “steady” state).
Synergi	A software product developed by DNV GL that models and analyzes power distribution systems in a real world spatial environment.
System Upgrade Cost	Certain costs that are evaluated at the distribution system level for a utility that are assessed to be required to enable distributed generation technology to interconnect. As detailed in this document, these costs do not include interconnection, secondary line impacts, communication and control system costs.
Transient	A state variable that changes during small time steps. For the purposes of this report, this term applies to changes that occur in intervals of less than one minute.

1. BACKGROUND AND SCOPE

This report presents analysis and results relating to the Virginia Solar Pathways Project (“VA SPP”) as investigated by Navigant and described in the Abstract and the following overview. It presents the study team’s project approach and assumptions applied to derive the findings presented herein, and includes details of the analysis consistent with project objectives.

1.1 Overview

The Distributed Solar Generation (“Solar DG”) study provides a partial analysis and a notional roadmap for Dominion Virginia Power (“DVP” or the “Company”) to safely and reliably integrate increasing amounts of solar DG capacity into its distribution system. The analysis and results presented herein address certain elements of the full cycle of solar DG from interconnection requests and protection requirements, to impact studies and operating on the grid. The analysis includes a postulation of the amount of solar that can be installed on DVP’s distribution system before it reaches a state of criticality, defined as a condition for which solar impacts and the cost to mitigate these impacts become significant. The study is designed to provide a framework under which Virginia and other regional utilities can evaluate solar impacts with a greater level of rigor, particularly with regard to dynamic impacts and technologies that enable the integration of greater amounts of DG.

1.2 Study Objectives and Scope

The study examines how increasing penetration of solar DG may impact grid stability, operability, and reliability on DVP’s system and identifies the critical levels of solar penetration and the distribution system upgrades required to ensure thermal loading, performance, and operational standards are within acceptable limits (i.e., do not violate DVP operational or planning standards or policies). It includes detailed analyses of DVP’s distribution system using state-of-the-art simulation tools to ensure accuracy and consistency with methods DVP currently uses for operational and planning studies.

Commensurate with the above, the study seeks to support the key policy objectives of the VA SPP:

- Integrate existing solar programs with new potential options appropriate for Virginia’s policy environment and broader economic development objectives;
- Promote wider deployment of solar within a low retail electricity rate environment; and
- Serve as a replicable model for use by other states with similar policy environments including, but not limited to, the entire Southeast region.

The report includes a benchmark analysis of best practices for Net Energy Metering (NEM) DG (less than 1 MW) and large DG (equal or greater than 1 MW), and technical studies to determine the maximum amount of solar that can be installed on DVP’s distribution system without system upgrades (e.g., hosting capacity threshold) under the assumption that solar would be installed throughout DVP’s service territory. It excludes interconnection costs that currently are uncertain but should be evaluated as installed solar capacity increases, and how the cost of upgrades may vary when solar is highly clustered in certain areas of DVP’s service territory. This study also assumes that NEM DG is located on feeders roughly in proportion to the number of customers located on feeder segments; while large DG is centrally located on each feeder. The study estimates impacts and additional costs for system upgrades once solar capacity

exceeds the hosting capacity threshold, and how these impacts can be mitigated via emerging technologies such as advanced inverter controls and energy storage.

1.3 Guiding Principles and Assumptions

Navigant and the DVP project team reviewed and when necessary, adjusted study methods and assumptions throughout the course of the study to ensure results are accurate and realistic. To ensure independent analytical rigor, Navigant prepared the following set of principles to guide the study team and to ensure these objectives were met throughout all phases of the study.

1. The methodology should be consistent with prior state-of-the-art industry studies, but with additional detail and analytical rigor.
2. The methodology should provide sufficient flexibility to update the analytical approach and results as new data become available (from both DVP and industry).
3. Comprehensive, industry-accepted simulation models and methods should be applied to produce the most accurate results.
4. Integration benefits and costs should be based on a realistic forecast of enabling solutions and commercially available technologies.
5. Study methods and results should be transparent and consistent with industry standards for solar technology assessment.
6. All assumptions, methods, and results are reviewed and vetted by a cross-section of DVP experts throughout the organization.

Key, overarching study assumptions are listed below. Detailed assumptions for distribution feeder selection and simulation studies are presented in their respective sections of this report.

- Reliability and performance must be maintained at current levels for DVP's distribution systems.
- Solar projects with total capacity less than 1 MW are connected behind the meter on secondary lines and services, with exports to the grid for higher solar capacity scenarios.
- Solar projects with total capacity greater than or equal to 1 MW interconnect directly to the primary distribution system.
- Distribution capacity deferral is not included in the benefits analysis due to the intermittent output of solar DG and radial configuration of most DVP distribution circuits.
- The analysis excludes evaluation of distribution impacts on DVP's secondary network systems, found in urban centers throughout DVP's service territory.²

Solutions to address constraints and violations are based on currently available technology; emerging technologies are evaluated as a longer-term solution

While the study attempts to quantify the resulting cost impacts of increasing solar DG capacity on DVP's system, the cost figures reflected in the study exclude certain significant costs that may be beyond the defined scope of this study but, nonetheless, are essential to assessing the true cost impacts of

² Secondary network systems deliver electricity to customers via an interconnected system of transformers and underground cables operating in parallel. This is different from radial systems, which deliver electricity to customers via a single path. Costs associated with interconnecting solar on a network feeder could increase system upgrade costs substantially. However, there are very few NEM or DG solar units installed on DVP's secondary networks and this trend is expected to continue for the foreseeable future.

integrating solar DG into the distribution system. Examples of cost components excluded from the study include telecommunications, monitoring and control systems, including Advanced Distribution Management Systems, that may be required for both NEM and individual DG units for high solar capacity scenarios.³ Additionally, large aggregation of NEM DG may trigger the need for system upgrades, which are then absorbed into the utility distribution budget and funded by all ratepayers. Also excluded are additional administrative, business process and overhead costs that DVP may incur as the amount of DG increases to levels where existing systems and processes will require modifications or enhancements, such as telecommunications infrastructure and automation technologies.

Accordingly, readers of the report are advised to view any conclusions with respect to cost impacts resulting from the study, as only a partial representation of actual costs of solar DG integration.

1.4 Report Contents

This report documents the methods and assumptions Navigant applied to derive results for two key Study 1 tasks: The first evaluates benchmarking and best practices. The second includes distribution analytical studies to identify the amount of solar DG that can be installed on DVP's distribution system without significant impact to electric system reliability and operations. An ancillary task includes evaluation of the role of emerging technologies to mitigate impacts and potentially increase the amount of solar capacity that can be installed, before impacts reach critical levels.

This report is also designed to inform the Core Advisory Team of the approach Navigant followed to evaluate solar DG impacts on the DVP's distribution system.⁴ The approach and methods Navigant applied to derive results and findings are presented in detail for the Benchmarking & DG Integration Best Practices and Distribution Analysis sections that follow.

Section 2 of this report summarize Solar Pathways Project objectives and the approach for the Distributed Solar Generation Integration & Best Practices Review (Study 1).

Section 3 presents the results of the steady-state and dynamic analysis, and the role of emerging technologies on DG integration benefits and system upgrade costs. Section 4 presents Navigant's findings and conclusions for the distribution study.

³ Applicants requesting interconnection are responsible for these costs, which are determined based on provisions and analysis associated with DVP's Interconnection Requirements.

⁴ Grid impacts on the higher voltage transmission system, including facilities rated above 69 kV, also are addressed in Study 2: "Solar PV Generation System Integration Impacts."

2. BENCHMARKING & DG INTEGRATION PRACTICES

The benchmarking analysis applies information obtained from current industry standards, best practices primary surveys, and other secondary research to create a framework for the evaluation and integration of solar DG. The knowledge obtained from this process provides a foundation to identify best practices for the safe and reliable interconnection of growing levels of solar DG at DVP and other Virginia utilities.

2.1 Practices Survey

Navigant conducted a survey of utilities with service territories comparable to DVP, in geographic size and number of customers, which have or are expected to interconnect large amounts of solar DG capacity. The utilities that participated are listed, below, with results to be shared with each under the condition that survey results will be “blind” without attribution to utility names or location.

- American Electric Power
- Dominion Virginia Power
- Duke Energy
- Eversource
- Hydro One
- National Grid
- Pacific Gas & Electric
- Southern California Edison
- Tucson Electric Power
- Xcel Energy

The attached questionnaire (Appendix A) was designed to identify industry practices for integrating solar DG onto an electric utility’s distribution system, and enable utilities and DG owners to safely and reliably interconnect solar DG. Results from the survey are combined with findings from a review of industry standards and secondary research to document best practices relating to DG integration.

The first set of questions requests general information on existing DG capacity and interconnection requirements. The next six categories address interconnection applications and practices, which include:

- DG Interconnection Process
- Grid Protection
- Operational Safety
- Grid Stability
- Telecommunications & Data
- Emerging Technology

For purposes of the survey, DG is defined as the maximum capacity that can be interconnected directly to the distribution system or substation (low-side bus). All references to DG are for solar photovoltaic (PV) systems.

Table 2-1 summarizes the leading practice from the survey and our subsequent analysis. Further discussion of each category is included in the sections that follow.

Table 2-1 Summary of Leading DG Interconnection Practices

Survey Category	Leading Practice
DG Interconnection Process	<ul style="list-style-type: none"> • Web-based application tracking and approval processes; few utilities have implemented these systems • Some utilities, including DVP, have organizations or teams solely responsible for DG interconnection tracking and review, with direct utility contact with customers for larger DG
Grid Protection	<ul style="list-style-type: none"> • Enhanced grounding protection for multi-phase DG • SCADA communications and control for larger DG
Operational Safety	<ul style="list-style-type: none"> • Automatic or remote disconnection of DG during feeder transfer during outages or maintenance
Grid Stability	<ul style="list-style-type: none"> • Analysis of potential dynamic impacts on feeder performance for high DG capacity • Automatic or remote disconnection of DG during feeder transfer during outages or maintenance
Telecommunications & Data	<ul style="list-style-type: none"> • Communications plan or strategy that includes integration of smart grid and DG technologies, including capability for monitoring and control of DG operations
Emerging Technology	<ul style="list-style-type: none"> • Advanced Distributed Energy Management (ADMS) for enhanced visualization and control of DG • Energy storage devices to mitigate DG impacts, including enhanced dynamic performance

Source: Navigant

2.1.1 DVP DG Interconnection Processes

Prior to contacting candidate utilities, Navigant interviewed DVP distribution engineering, operations, and planning staff to ascertain DG interconnection processes and requirements. In Virginia, utilities must comply with Virginia State Corporation Commission (VA SCC) Regulations Governing Interconnection of Small Electrical Generators (20 VAC 5-314-10 et sec.) regarding interconnection of electric generating facilities of 20 megawatts or less. The VA SCC also has Regulations Governing Net Energy Metering (20 VAC 5-315-10 et sec.) which govern interconnection of net metered generation facilities up to 20 kW for residential customers and up to 1 MW for non-residential customers. In this context, DVP requirements comply with Chapter 314 regulations and Chapter 315 regulations, but with clarification with respect to screening of DG interconnection requests and combined studies. Although the amount of existing DG is relatively small in Virginia (e.g., about 10 MW of NEM solar DG is currently installed), the number of requests in the interconnection queue and customer (or third-party) interest in solar indicate pending application requests are expected to increase over time. In addition, without significant automation or process changes, DVP's ability to respond in a timely manner could become constrained, and may result in delays in non-NEM interconnection approvals of 1 MW and greater .

The DG application process in Virginia requires that all interconnection requests be evaluated. Those requests deemed to cause impacts may require upgrades, changes in DG operation, or other forms of mitigation to address potential impacts. Navigant determined that DVP has proposed very detailed and clear guidelines and requirements for future DG to address both steady-state and dynamic impacts.

Further, DVP has established a coordination function with resources dedicated to handling applications for interconnection. It includes use of DG application tracking systems to ensure timely and thorough review and approval of interconnection requests. While effective, there would be opportunities to streamline the process via automated systems, such as web-based interconnection application review and approval for NEM applications. There are also concerns about the ability to scale the existing manual processes and systems to sufficiently handle a growing interconnection request queue. In addition to this process, there is a FERC process in Virginia to connect distributed generation through a PJM interconnection.

2.2 Utility Interconnection Practices

The following summarizes Navigant's observations regarding utility DG interconnection best practices, based on interviews and survey results received from DVP and other survey participants.

2.2.1 DG Interconnection Process

In some instances, the required timelines are consistent among all utilities within a single state. For multi-state utility holding companies, there are attempts to be consistent, but there are differences as each state or utility maintains separate policies and procedures. All utilities offer fast-track or expedited approval for smaller DG (e.g., 25 kW and below), particularly for inverter-based technology such as solar DG. In some cases, the rules do not limit the amount of DG that can be installed on individual feeders. A few utilities raised concerns that NEM rules do not allow utilities to recover costs when large aggregation of DG triggers the need for system upgrades, which are then absorbed into the utility distribution budget and funded by all ratepayers.

All 12 utilities surveyed maintain web sites that contain information on whom to contact to inquire or request application for interconnection. The contact may be either through customer service representatives or with a coordinator responsible for DG interconnection requests. Utilities with very large numbers of applications for interconnection typically assign one or more coordinators to handle the application and conduct an initial screening to determine eligibility for fast-track or expedited approval, effectively forming a DG interconnection team. The coordinator(s) then forwards applications that do not qualify for expedited approval to a technical group for review and determination of whether a detailed system impact study is required. Some utilities will assign DG technical reviews to groups within technical departments, such as Distribution Planning, whose sole responsibility is to conduct impact studies. Other utility distribution organizations assign DG reviews to staff that also are responsible for internal studies. Again, utilities with a large number of applications for interconnection will, as a leading practice, dedicate technical teams with sole responsibility to evaluate interconnection requests, often to meet deadlines established in each utilities' interconnection agreements.

Only 4 of 12 utilities surveyed have implemented a web-based platform to access, manage, and process NEM requests for interconnection, with one indicating the software supplier (Salesforce). All utility web sites contain contact information or enable potential applicants to download application forms, but only the 4 previously cited allow applicants to interactively enter information and data for their project. Several utilities stated that they either plan or are evaluating web platforms and associated systems to streamline the process, particularly those who have, are or expected to have, a large number of interconnection requests. Those considering, or moving forward, with web-based platforms, are planning to create systems with comprehensive application management, tracking, and evaluation of DG requests to improve the efficiency of existing processes. The most important feature of proposed systems is the

replacement of manual, spreadsheet-based tracking systems with a common platform and databases, with improved capability to coordinate and process internal workflows, and application review and approval.

2.2.2 Grid Protection

Navigant found some variance in utility protection practices for DG, an expected outcome given the differences in utility protection philosophy and practices, particularly at the distribution level. While all utilities have adopted practices that require applicants for interconnection to meet IEEE 1547 standards, such as minimum clearing times, some have adopted enhanced protection to address specific distribution system design and attributes or other unique aspects associated with their respective systems.

One of the most significant variances in protection practices is the level at which anti-islanding limits are set. Five utilities rely on inverter anti-islanding protection schemes to meet the current IEEE 1547 standard⁵ of a two-second maximum trip interval, following the operation of a protective device; five utilities also indicated anti-islanding is required (two utilities provided no response). The first group of utilities cite the effectiveness of current inverter isolation schemes; the most advanced include active detection schemes that reduce the conditions (often referred to as the window of exposure)⁶ under which islanding could occur, with several noting the absence of any violations to the two-second standard. In contrast, the five utilities that require anti-islanding schemes either set limits on the amount of solar (and for distributed generation, in general) that can be installed on a feeder or protective zone, or require SCADA communications and transfer tripping to ensure DG isolation following a fault. The IEEE 1547 guidelines suggest, as an example, maximum allowable DG capacity equal to one-third of the minimum load, and some utilities have adopted values close to the standard. For example, at least one utility has set a limit of total aggregate DG capacity at 50% of the annual minimum feeder load.

As noted, utilities that allow DG capacity to exceed the minimum feeder load also require DG owners to install transfer-trip schemes that lock out the inverter breaker or isolating device, upon detection of an operation of a utility circuit breaker or other protective device. However, the transfer-trip requirement typically applies only to large-scale DG (sometimes referred to as utility scale), as the installation of transfer-trip schemes is uneconomic for smaller DG. Most of the utilities surveyed did not report a condition under which aggregate solar capacity has exceeded this threshold. The latter issue is potentially complicated by state NEM interconnection rules, many of which obligate the utility to accept all DG interconnection requests up to the individual DG facility NEM capacity threshold, which may be up to 1 MW or higher in some jurisdictions.

A few utilities, including DVP, apply enhanced protection (i.e., beyond minimum levels required to comply with IEEE 1547 or applicable codes) under some conditions to ensure distribution lines, where DG is present, operate safely and reliably. At least two utilities, including DVP, require enhanced grounding protection on larger inverter-based devices to avoid temporary overvoltages on utility lines, after the line is isolated due to operation of a breaker or other protective device. These measures include use of neutral voltage relays or grounding transformers to limit overvoltages.⁷ Some utilities expressly avoid the

⁵ IEEE 1547 "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems" July 28, 2003.

⁶ The window of exposure can vary significantly depending on several factors, including feeder configuration, voltage, and load on an isolated segment, location, and rating of reactive devices (e.g., capacitors), power factor, and other feeder-specific attributes.

⁷ Inverters such as those used to convert solar direct current (DC) output to alternating current (AC) typically are not designed to supply zero sequence fault current, thereby causing voltage rise by up to 70% on unfaulted phases during the interval when a utility protective device opens and the DG unit stops providing fault current to the system.

latter practice, suggesting the time interval when overvoltage could occur is too brief to cause damage or, alternatively, may de-sensitize protection schemes. Navigant's experience, including direct responsibility for utility operations, recognizes the adoption of different protection practices among utilities, as there is often no single approach or standard associated with system protection practices.

2.2.3 Operational Safety

Virtually all utilities surveyed have policies and procedures designed to protect crews and the general public from hazards associated with potential islanding of DG, while electric utility lines are de-energized for maintenance or repairs, although specific operating practices appear to vary. For larger DG equipped with telecommunications and controls (e.g., typically 1 MW or larger) integrated with a utilities' supervisory control and data acquisition (SCADA), most utilities will remotely disable DG until service is restored. Interconnection agreements for larger DG typically allow the utility to remotely disable under various conditions, including repairs and emergencies. However, operating practices for small DG, including DG without communications and controls integrated to SCADA, tend to have minor differences that reflect the general work practices at each respective utility. For example, some utilities, including DVP, have blanket practices where crews must assume DG is present and potentially operating, even if there is no direct evidence of DG on the line or at a customer premise. A common response from utilities was that "we always assume lines are hot" during line work or repairs. Utilities noted that they apply standard isolation and grounding practices on both ends of de-energized line sections to ensure DG units will immediately trip off line if energized. A few will also open line fuses and disconnect switches to ensure DG is isolated. All utilities require a visible disconnect at the owner's facility, and some will open and tag each disconnect during maintenance or emergencies. No utility reported any anomalies or safety conditions caused by unintended islanding of DG that caused them to implement enhanced safety policies or procedures, or improved protective devices.

2.2.4 Grid Stability

All utilities surveyed cited concerns regarding voltage impacts, typically found as potential steady-state overvoltages caused by connecting an amount of DG capacity that begins to approach the feeder thermal rating. Virtually all apply commercial tools⁸ similar to those used by DVP to evaluate potential impacts and identify solutions to mitigate impacts during the pre-screening, or impact study phase, of interconnection applications. These tools are also used to assess DG impacts caused by feeder reconfiguration, load balancing, and load growth. Although several utilities also raised concerns about dynamic impacts, including short-term voltage rise and stability, Navigant found that only 3 of the 12 utilities surveyed indicated dynamic impacts are evaluated as part of the application process. Some indicated dynamic impacts could arise as part of a detailed system impact study. Although a concern, the widespread use of dynamic models for time-series analysis, and stability models for voltage analysis, is not currently a common practice among the survey group. For example, utilities will evaluate potential dynamic impacts for large DG interconnection applications. Similarly, some utilities commented that they might initiate dynamic studies when conditions for load ratio, short circuit capacity, and feeder voltage suggest such a review is necessary. Only two utilities indicated that a standard PV model is applied, and these are modeled solely in transmission network models for larger DG, requesting interconnection to higher voltage lines.

Most utilities surveyed indicated feeder load transfers, via ties to adjacent feeders, as an issue considered when evaluating interconnection requests. Most utilities apply steady-state models described

⁸ E.g., CYMDIST, Synergi, Milsoft.

above to determine DG impacts and limits for reconfigured circuits.⁹ Most utilities also limit the amount of DG capacity on a feeder based on the reconfigured circuit, following the transfer of a feeder segment for outage restoration or scheduled maintenance, including those controlled by auto-transfer schemes. Most utilities disconnect larger DG (typically 500 to 1,000 kW or higher) via SCADA, rather than transfer it to another feeder. When potential violations are detected, most utilities authorize interconnection on the condition that the DG owner agrees to discontinue operation and is responsible for the installation of SCADA telecommunications to enable distribution operators to remotely disconnect the DG unit. However, use of SCADA for remote disconnection typically is feasible for larger DG as it is uneconomic for small DG, such as projects for residential and small commercial installations. Utilities acknowledged that NEM DG potentially could be an issue where total aggregate NEM DG may exceed limits, but the utility is required to interconnect. This might require utilities to incur additional costs to mitigate impacts, which would then be passed along to ratepayers.

2.2.5 Telecommunication and Data

At least 5 utilities require SCADA telecommunications and controls for larger DG to enable direct access by distribution operators, or for automated transfer-trip schemes. Of these, telecommunications are required when DG is larger than 1 MW, but are required for projects as low as 250 kW for one utility. One utility indicated SCADA telecommunications is required for any DG that could impact operations, but typically applies only to larger DG due to costs (owners of smaller DG typically withdraw the application due to high costs).

One utility surveyed has deployed fully-automated distribution monitoring, designed to control DG during tie transfers and other applications, although those with a distribution management system (DMS) not designed for DG management indicate improved situational awareness of feeders with large amounts of DG capacity. On the distribution level, no utilities reported that DG power factor is actively controlled. However, about half the utilities reported they require larger DG to passively set power factor at non-unity when required to manage voltage. Utilities that have deployed advanced metering infrastructure report that these systems may be used to collect DG output information, but are not suitable for active control due to telecommunications network or metering limitations. Some utilities report implementation of pilot programs to evaluate advanced DG data collection and active control. This includes utilities in California, where state mandates now require utilities to include distributed energy resources (DER) in distribution planning, and to consider DER as an alternative to traditional distribution solutions and capacity additions.¹⁰

Virtually all utilities collect DG real power output for larger DG, or require the project owner to collect the data and forward it to utilities upon request. However, only a few utilities have implemented comprehensive data acquisition and management systems for DG via automated schemes, where data is captured via SCADA/DMS, stored on databases, and analyzed via software systems. Some report that plans are underway to deploy management systems to capture and analyze data. As noted, limitations on

⁹ Feeder transfer studies are not required for utilities with limited tie capacity, such as feeders in rural areas where back-up capability is limited or non-existent

¹⁰ Assembly Bill 327 directed the California Public Utility Commission to implement rules that require investor-owned utilities to prepare Distribution Resource Plans (DRP) outlining how each proposes to maximize DER benefits and capacity, including estimates of hosting capacity (i.e., how much capacity the distribution system can accept without upgrades) and methods to enhance DER integration. Some utilities report plans to implement pilot programs to evaluate advanced DMS for DER data capture and active control; and some propose significant investment programs to implement comprehensive communications, distribution system management and upgraded systems to meet DRP objectives such as assignment of firm capacity to DER and increases in feeder hosting capacity.

telecommunications systems or smart metering networks generally prohibit active control, but may be used to download data via scheduled retrieval intervals.

2.2.6 Emerging Technologies

The review of emerging technologies included use of advanced systems and energy storage to mitigate DG impacts and enable greater amounts of DG capacity. At least 2 utilities surveyed indicated energy storage, mostly pilot applications, have been installed or underway to mitigate DG impacts. These utilities, and other utilities with DOE-sponsored projects, have demonstrated the potential for advanced systems to significantly enhance a utility's ability to integrate greater amounts of DG and to increase the benefits associated with DG. Direct benefits include improved system efficiency, increased resiliency, and lower cost.

3. DISTRIBUTION ANALYSIS

In addition to the benchmarking analysis, this study quantifies certain impacts of increasing amounts of solar DG capacity on DVP's system. The primary objective is to determine critical levels of solar capacity that can be installed on DVP's distribution feeders without significant impact and the need for associated distribution system upgrades (e.g., reconductoring lines, converting single phase circuits to three phase) to mitigate impacts (e.g., overvoltage, thermal overloading). It includes connection, but excludes the cost telecommunications, monitoring and control systems, including Advanced Distribution Management Systems that will be required for both NEM and individual DG units for high solar capacity scenarios.¹¹ Also excluded are additional administrative, business process and overhead costs that DVP may incur as the amount of DG increases to levels where existing systems and processes will require modifications or enhancements, such as telecommunications infrastructure and automation technologies.

Navigant also investigated the role of emerging technologies to reduce impacts and enhance value, including advanced technologies to better integrate solar DG via telecommunications and controls. The following sections present the methods and simulation models Navigant used to predict solar capacity impacts, and corresponding mitigation options to address these impacts and increase solar hosting capacity thresholds.

3.1 Overview and Approach

The first step in the analysis entails the selection of a subset of DVP's feeders that are statistically representative of the entire population of DVP's 1,800 distribution feeders. The approach is based on a mathematical grouping of feeder properties such as feeder voltage, peak load, feeder length, and customer density. Navigant's experience suggests 10 to 12 feeders are sufficient for evaluating utilities with a similar number of feeders as found on DVP's system. A detailed description of the feeder selection process and set of representative feeders is presented in subsequent sections.

While there is no way to accurately predict the location of solar DG projects that developers will request interconnection, Navigant identified where small solar DG capacity is most likely to be installed in DVP's service territory based on factors such as customer load and demographics. Solar capacity was first assigned to one of 15 geographic zones DVP uses for transmission studies. The total amount of solar capacity within each zone was then assigned to individual feeders within each zone. These steps are further described in section 3.2.3. Equally important is where solar capacity is likely to be installed on each feeder. Navigant determined where solar DG systems are most likely to be installed on each of the representative feeders, and then allocated total solar capacity to these locations (hereafter referred to as "feed-in" points or nodes), based on the number and type of customers on individual feeder line segments.

Following the allocation and assignment of solar capacity to representative feeders, load-flow simulation analyses were performed for each of the representative feeders for increasing amounts of solar DG capacity. The objective is to identify the maximum amount of solar DG that can be installed on each representative feeder (i.e., point of criticality) using simulation models designed to predict distribution system impacts. The simulation models and level of rigor in these studies is consistent with the tools and methods DVP uses for internal distribution analysis. Specifically, the distribution analysis includes an assessment of each of the following operational issues and criteria associated with solar DG:

¹¹ Applicants requesting interconnection are responsible for these costs, which are determined based on provisions and analysis associated with DVP's Interconnection Requirements.

- Overhead (OH) and underground (UG) line loadings
- Feeder voltage and reactive support
- Power quality (e.g., voltage flicker)
- Protection system impacts
- Operational constraints (e.g., tie transfer issues, recloser operation, load transfer)
- Feeder regulator and capacitor operations (to minimize accelerated failure)
- Other factors specific to isolated circuits, as determined by discussions with key DVP distribution planning, engineering, and operations staff.

Based on the results of the feeder simulation studies, the amount of solar capacity on DVP's existing distribution system was estimated. Once identified, options for increasing solar capacity above the criticality threshold were evaluated, including:

- Capacity upgrades (e.g., OH/UG lines, substation transformers, new power lines, new substations)
- New voltage regulating devices, or adjustments in station voltages and settings
- Enhanced protection systems
- New information systems to maintain an accurate inventory of DG interconnections
- New or upgraded protection systems
- Feeder reconfiguration
- Increased tie capacity
- Special operating procedures (e.g., for line maintenance, load transfer)
- New controls and monitoring (including telecommunications for transfer tripping)
- Passive inverter power factor control.

Once impacts and the potential mitigation options are evaluated for each representative feeder, results were extended to DVP's total population of feeders (i.e., a single feeder type may represent 25 to 200 DVP feeders).

In addition to traditional mitigation solutions, emerging technologies such as energy storage systems, low-voltage regulators, and smart inverters were included in the analysis. It includes evaluation of the following options and operational requirements:

- Grid protection considerations for the interconnection of energy storage systems
- Infrastructure and metering considerations for the interconnection of energy storage systems
- Telecommunications between the utility and solar DG site, for transfer-trip or other protection needs to transfer signals between entities
- Operational considerations for the interconnection of energy storage systems
- Effects of advanced features and functionalities of inverters on grid stability (including benefits of customer-controlled vs. utility-controlled inverters)
- Evaluation of smart inverter capabilities and applications such as remote control, dispatching, and operator commands

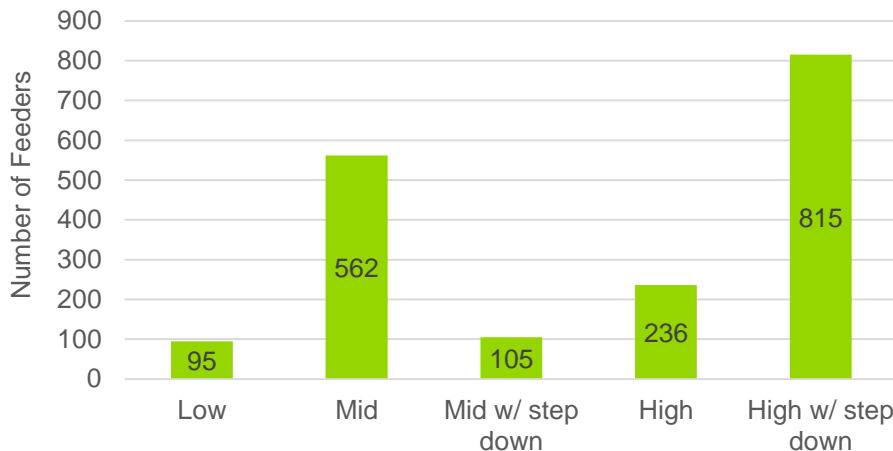
- Capability to successfully integrate greater amounts of solar capacity on the distribution system
- Advanced distribution management systems (ADMS) to manage the above applications and functionality.

Navigant’s use of representative feeders provides for an accurate comparison and more efficient evaluation of DG for increasing amounts of solar capacities. The overarching goal of the analysis is to produce results that are relevant to, and implementable within DVP’s distribution planning processes, including future research of solar DG impacts and mitigation solutions using advanced inverter controls and energy storage.

3.2 DVP Distribution System and Solar Allocation

The DVP distribution system is characterized by a mix of urban, rural, and suburban load serving some of the largest metropolitan areas and very rural areas in the states of Virginia and North Carolina. There are approximately 1,800 distribution feeders operating at voltages ranging from 4.0 kV to 46.0 kV, which includes many circuits operating at more than one voltage. This includes 34.5 kV lines originating at the substation bus, with mid-line step-down transformers delivering energy at 12.47 or 4.16 kV. Figure 3-1 lists the number of feeders operating at single or multiple voltages—over 50% of feeders operate at multiple voltages.¹²

Figure 3-1. Population of DVP Feeders by Voltage Class¹³



Source: Navigant analysis of DVP data

¹² Some distribution feeders serve lower voltage substations, each of which may have multiple feeders. Lower voltage feeders on these substations are defined feeders and included in the 1,800 total population of feeders.

¹³ ‘Low’ represents feeders with a primary voltage of 4.0, 4.16, and 6.0 kV. ‘Mid’ represents feeders with a primary voltage of 11.0, 12.5, 13.2, 13.8 and 23.0 kV. ‘High’ represents 34.5 and 46.0 kV feeders.

The key attributes of DVP's distribution system are summarized in Table 3-1 and in Table 3-2. Notably, many DVP feeders operate at 34.5 kV, typically the highest operating voltage for distribution systems in the U.S.¹⁴ Feeders operating at higher operating voltages typically serve higher loads and many are longer, some up to 200 miles or more. These lines, on average, also are "stiffer," thus less prone to voltage deviations, which is an important factor in studies evaluating the capability of feeders to integrate DG. The feeders with a step-down transformer are typically longer and serve more customers than other feeder types. Whereas, the low-voltage feeders are, on average, the shortest and serve fewer customers and less load.

Table 3-1. Aggregated DVP Feeder Properties by Voltage Class

Voltage Class	Number of Feeders	Total Length (miles)	Total Customers Served	Total Non-Coincident Peak (MW)
Low	95	255	28,550	114
Med	562	9,124	405,191	2,327
Med w/ Step-Down	105	2,583	115,110	590
High	236	2,075	151,818	1,885
High w/ Step-Down	815	43,215	1,838,549	10,655
Total	1,813	57,252	2,539,218	15,570

Source: Navigant analysis of DVP data

Table 3-2. Average DVP Feeder Properties by Voltage Class

Voltage Class	Average Length (mi)	Average Customers Served	Average Non-Coincident Peak (kW)
Low	2.7	301	1,199
Med	16.2	721	4,140
Med w/ Step-Down	24.6	1,096	5,617
High	8.8	643	7,987
High w/ Step-Down	53.0	2,256	13,073

Source: Navigant analysis of DVP data

3.2.1 Feeder Selection Process

The distribution impact analysis requires the selection of a statistically representative feeder sample to assess the benefits and costs of solar DG. The selection of a representative set of feeders avoids the inherent constraints and inefficiencies associated with attempting to simulate the impact of DG on all DVP feeders, while providing a sound basis for predicting system-wide costs.

¹⁴ DVP is one of the earlier adopters of 34.5 kV distribution in the U.S.

Navigant performed standard k-means clustering of 1,565 feeders to develop an operationally representative sample of DVP’s system in Virginia and North Carolina. This number is a subset of the entire system, which consists of over 1,800 feeders. The distribution impact analysis focused only on feeders located in Virginia. Further, several feeders serving secondary networks or dedicated to individual customers and therefore unlikely to connect solar generation were eliminated from the total set.¹⁵ The clustering was performed based on the feeder properties listed in Table 3-3. These properties were selected to diversify feeder clusters to best represent DVP’s entire distribution system.¹⁶ The weighting of feeder properties also reflects the significance each is likely to have with respect to DG impacts on feeder performance. For example, the amount of solar DG that can be installed on a feeder is highly dependent on feeder voltage—typically, the higher the feeder voltage, the greater amount of DG capacity that can be installed before criticality is reached.

Table 3-3. Key Feeder Properties and Weighting Factors

Property	Weighting Factor
Voltage	8
Mileage	8
Load (kVA)	8
Low/High-Voltage Ratio	8
Customer Count	3
% 3 Phase Miles/Total Mileage	3
% Industrial Load	3
% Overhead Miles/Total Mileage	3
% Commercial Load	1
% Residential Load	1
Number of Line Regulators	1

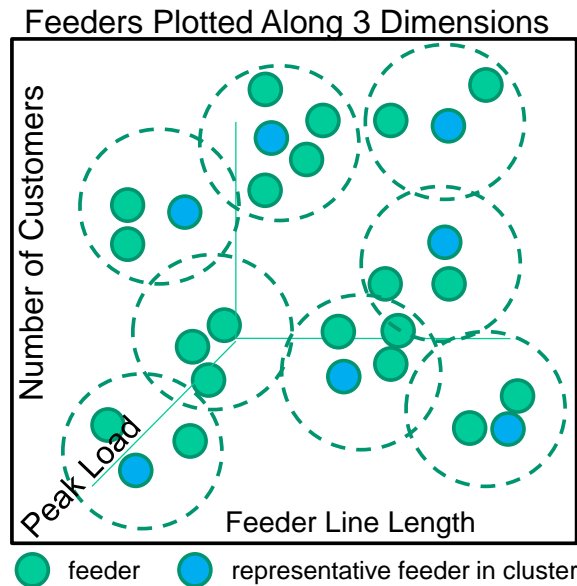
Source: Navigant

¹⁵ Over 50 feeders serve grid or spot network systems in Norfolk, Richmond, Crystal City, and Roslyn areas with total connected load of approximately 350 MW. An additional number of circuits were dedicated to external customers, industrial feeds, or were resale delivery points in non-Dominion service territory.

¹⁶ The feeder selection methodology applied in Navigant’s analysis is based on a statistical approach developed in the early 1980’s and subsequently applied by utilities and industry analysts. Further reference on the foundation and methodology to this approach is described in the research paper, “A Cluster-Based Method of Building Representative Models of Distribution Systems,” H. L. Willis H. N. Tram, and R. W. Powell, IEEE Transactions on Power Apparatus and Systems, March 1983, p. 1776.

The clustering algorithm used to select representative feeders seeks to define a number of fixed subsets of feeders in the entirety of DVP’s system. The profile of the representative feeder selected for each of the defined subsets is the one that best represents a larger set of feeders with common attributes in DVP’s system. For example, one feeder may represent 34.5 kV distribution feeders that are relatively long with a large number of residential customers. A graphical depiction of the results produced by the feeder selection algorithm is presented in Figure 3-2.¹⁷ In the three-property illustration, the comparison of individual feeders to the average profile is repeated until the difference between the properties in each group is sufficiently small.

Figure 3-2. Graphical Depiction of K-Means Algorithm Results (Illustrative)



Source: Navigant

The above process and the properties used to account for PV impacts resulted in the selection of 14 representative feeders for DVP’s distribution system.¹⁸

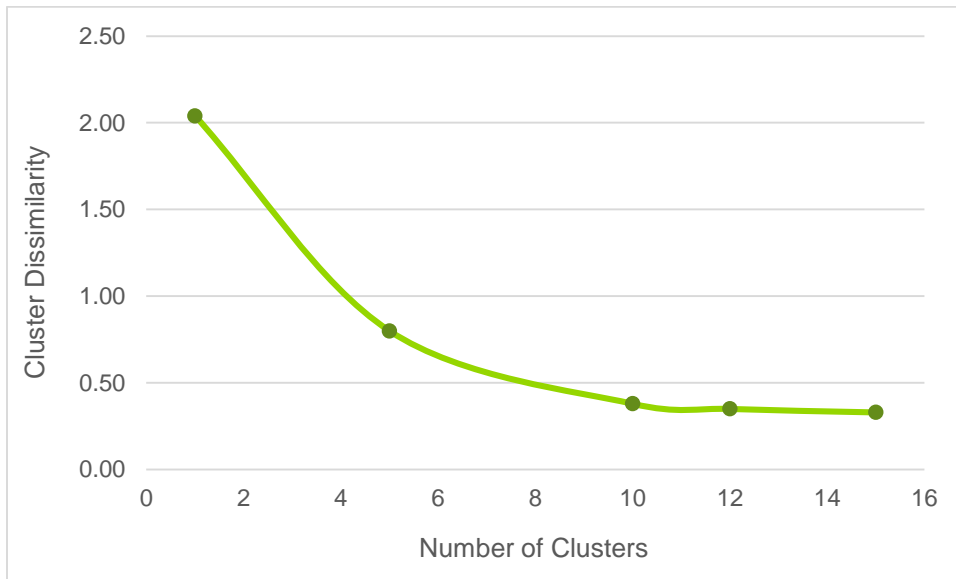
As noted, 10 to 12 representative feeders is usually sufficient for a distribution system comparable in size to DVP. However, DVP’s system configuration departs from those of many other utilities due to the predominant use of 34.5 kV distribution and the large number of multi-voltage feeders. That is, many feeders are equipped with step-down transformer banks that convert higher primary voltages to a lower voltage. While common in industry, the large number of step-downs—over 50% appear in Figure 3-1—suggests a larger number of distribution feeders is needed to accurately represent DVP’s system.

¹⁷ The algorithm was implemented using Microsoft VBA, as several iterations are required to group feeders into clusters with common attributes and to identify the feeder that best represents the cluster. The feeders with the most similar properties are placed in the same group.

¹⁸ The boundary condition used to select a representative set of feeders is based on an assumption that there is sufficient similarity in feeder attributes within each cluster that additional representative feeders will not result in increased similarity in feeder clusters (using Euclidean distance, the standard comparison parameter in k-means clustering).

To determine the minimum number of representative feeders, Navigant performed a “Scree” analysis of DVP’s total population of feeders.¹⁹ Individual feeder properties were compared to the average system properties to determine the dissimilarity metric. This metric was then recalculated for each instance where the system was divided into one additional cluster. Graphically, Figure 3-3 confirms that after 10 clusters, system dissimilarity does not significantly change. To achieve a greater level of accuracy and to account for the many step-down feeder configurations, Navigant increased the minimum sample to 14 feeders.

Figure 3-3. Feeder Selection Scree Test



Source: Navigant

3.2.2 Representative Feeder Profiles

The final set of feeder clusters and their average properties appears in Table 3-4. Navigant selected representative feeders within each cluster with attributes that were closest to the average feeder profile. The representative feeders that Navigant selected and the number of feeders within each cluster appear in Table 3-5. The representative feeders are assumed to have properties sufficiently similar all other feeders within a cluster such that simulation model results for the representative feeder will be comparable to all other feeders in each cluster.²⁰

¹⁹ A scree analysis identifies the point at which adding additional clusters does not materially improve accuracy, measured by comparing the total “distance” of each feeder within the cluster to the centroid.

²⁰ For example, 129 feeders are assigned to cluster Number 1. In the analysis that follows, 129 feeders in DVP’s service territory are assumed to have the same attributes and impacts predicted based for a single representative feeder.

Table 3-4. Number of Feeders per Cluster and Average Cluster Profiles

Cluster	Number of Feeders	Voltage	Miles Rounded	% 1 Phase	Load (kW)	Cust Count	% RES Load	% COM Load	% IND Load	Number of Line Regulators	%OH	%UG	Low/High-Voltage Ratio
1	171	34.50	18	32%	15,394	1,488	26%	64%	10%	0	25%	75%	0.04
2	358	12.50	27	66%	4,993	1,186	75%	24%	0%	0	80%	20%	0.01
3	100	34.50	7	13%	6,018	326	15%	68%	11%	0	53%	47%	0.02
4	76	4.16	3	46%	1,369	373	80%	18%	0%	0	95%	5%	0.00
5	53	13.20	6	17%	3,651	255	11%	80%	7%	0	41%	59%	0.01
6	38	34.50	198	81%	14,357	2,797	63%	29%	1%	2	77%	23%	0.63
7	156	34.50	35	58%	11,045	1,939	58%	36%	4%	0	69%	31%	0.17
8	21	34.50	42	54%	9,505	833	29%	66%	1%	0	79%	21%	0.67
9	52	34.50	74	66%	9,662	1,646	57%	30%	2%	0	77%	23%	0.90
10	96	34.50	73	76%	16,063	3,299	74%	25%	1%	0	32%	68%	0.31
11	81	34.50	62	64%	10,901	1,882	58%	34%	2%	0	70%	30%	0.46
12	140	34.50	10	33%	5,346	539	28%	49%	16%	0	85%	15%	0.03
13	184	34.50	50	71%	16,273	3,397	73%	26%	1%	0	27%	73%	0.07
14	31	34.50	58	73%	13,756	2,561	75%	24%	1%	0	36%	64%	0.69

Source: Navigant

Table 3-5. Representative Feeder Profiles

Cluster	Feeder ID	Voltage	Miles Rounded	% 1 Phase	Load (kW)	Cust Count	% RES Load	% COM Load	% IND Load	Number of Line Regulators	% OH	% UG	Miles of Line <34.5 kV
1	25360	34.50	24	40%	15,384	1,275	24%	70%	6%	0	27%	73%	0.00
2	26771	13.20	15	71%	5,627	1,155	74%	26%	0%	0	91%	9%	15.00
3	46366	34.50	9	14%	8,536	742	22%	78%	0%	0	60%	40%	0.00
4	05849	4.16	4	41%	934	276	79%	21%	0%	0	97%	3%	3.78
5	01600	13.20	1	2%	3,406	255	11%	89%	0%	0	45%	55%	1.13
6	06431	34.50	192	77%	13,484	2,417	62%	38%	0%	2	70%	30%	50.95
7	46780	34.50	20	56%	10,936	2,107	57%	43%	0%	0	66%	34%	1.13
8	67326	34.50	39	60%	5,516	750	37%	63%	0%	0	84%	16%	22.07
9	84345	34.50	75	77%	8,668	2,044	57%	43%	0%	0	74%	26%	38.20
10	43419	34.50	58	76%	17,621	4,037	83%	17%	0%	0	30%	70%	11.68
11	81368	34.50	57	59%	10,882	3,031	66%	34%	0%	0	66%	34%	15.68
12	25726	13.20	8	30%	3,959	500	43%	57%	0%	0	83%	17%	8.05
13	42478	34.50	55	72%	15,232	3,565	74%	26%	0%	0	24%	76%	0.89
14	25467	34.50	41	75%	13,912	2,262	75%	25%	0%	0	37%	63%	19.23

Source: Navigant

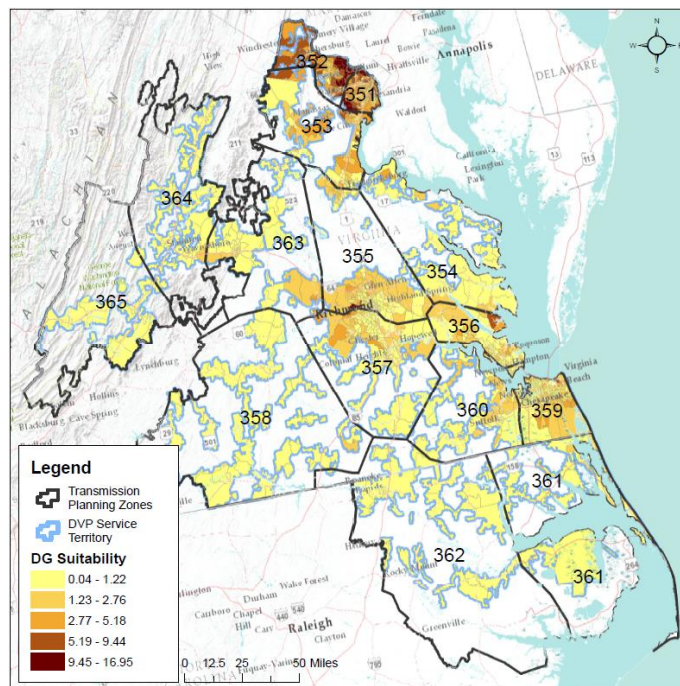
3.2.3 Solar Capacity Levels and Allocation²¹

The allocation of solar DG capacity to locations throughout DVP’s service territory is an important part of the analysis, as the amount of solar DG capacity installed is a function of number and type of customers per feeder, which may not be the same throughout different segments of DVP’s service territory. Solar DG capacity is assumed to be a function of the number of customers in an area, adjusted to reflect economic drivers that promote or encourage the purchase of solar DG.

For solar DG, Navigant used a combination of residential and commercial customer load, household income, and home values to allocate solar DG capacity to each transmission zone. The U.S. census provided average incomes and housing values in each zone, each with equal weighting, to develop suitability scores.

The use of customer load, and housing and income values, each with equal weighting, produced DG suitability scores for each census tract in each transmission zone for solar DG. Figure 3-4 illustrates the DVP distribution service territory and which areas are more likely than others to experience higher penetration of solar DG. The scores tend to be higher in areas with higher customer counts, and higher income and housing values, such as areas near Richmond and northern Virginia. These trends appear to match those presented in Figure 3-5 below for existing NEM, particularly in northern Virginia, where housing value and income is up to twice the average compared to other parts of the state.

Figure 3-4. DG Suitability by Transmission Zone

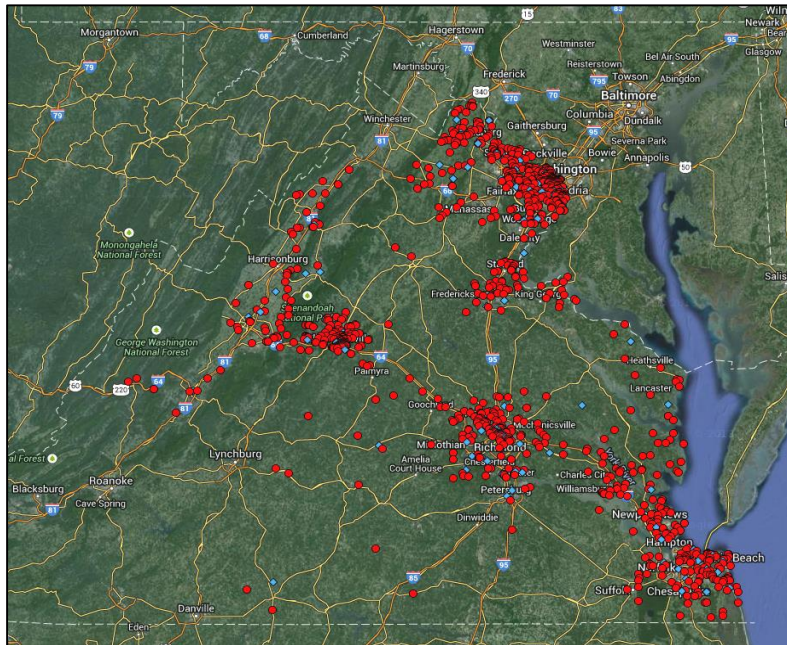


Source: Navigant

²¹ The solar capacity allocation presented in this section also appears in an adjunct Study 2 Report on grid level impacts, as the impact of solar DG on the transmission grid and generation system is part of Study 2 objectives.

For comparison, allocations from Figure 3-4 are compared to existing NEM data. Currently, there are approximately 1,400 residential and commercial NEM customers in DVP’s Virginia service territory with solar DG, for a total of 10 MW of installed capacity. The vast majority of these installations are 10 kW and lower. Figure 3-5 illustrates the location of existing NEM, which confirms most are located in more densely populated urban areas.

Figure 3-5. Existing NEM Locations in DVP’s Virginia Service Territory

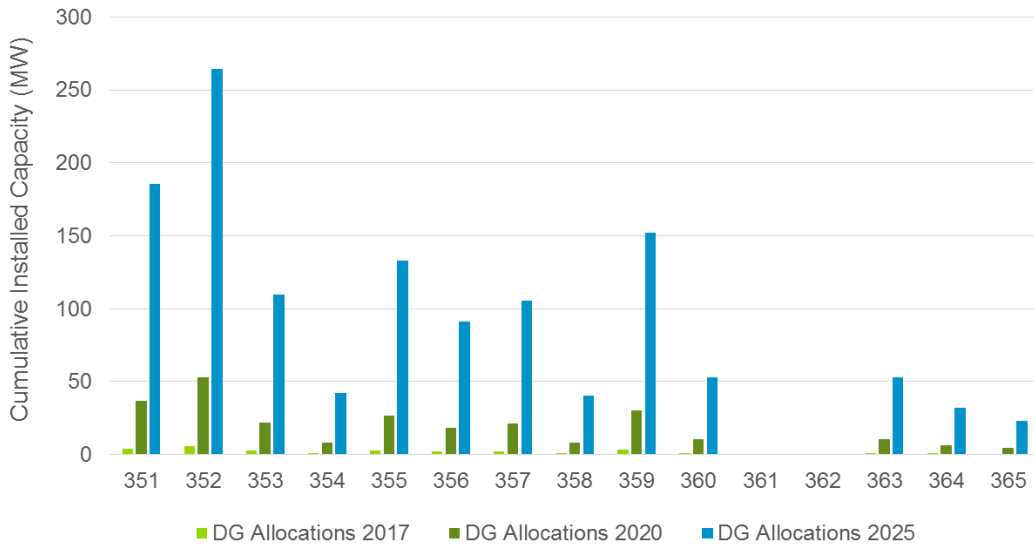


*Residential locations in red; commercial locations in blue
Source: DVP*

The census data approach results in greater clustering of DG, which represents a more realistic outcome for small solar DG, based on nationwide trends. The most significant deviations typically occur in rural areas due to lower average housing values and income. Existing NEM data, while limited within DVP’s service area, confirm that zones with higher average household income and greater average home values, such as Richmond and northern Virginia, are likely to have greater DG capacity installed per customer.

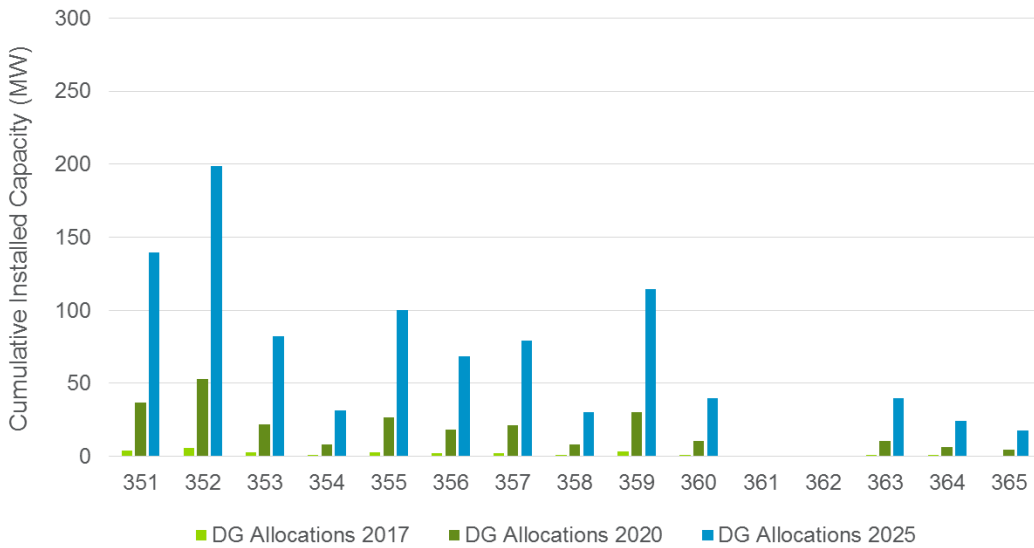
Navigant applied the suitability scores, in combination with customer census data, to allocate total solar capacity forecast to individual zones. Figure 3-6 and Figure 3-7 presents DVP’s 2015 Integrated Resource Plan (IRP) Plan A and B DG capacity allocation for 2017, 2020, and 2025. There is no DG assigned to Zones 361 and 362, as each are predominantly in rural North Carolina.

Figure 3-6. DVP 2015 IRP Plan A Solar DG Capacity Allocations²²



Source: Navigant

Figure 3-7. DVP 2015 IRP Plan B Solar DG Capacity Allocations



Source: Navigant

²² Virginia currently has a Net Metering Capacity Cap of 1% of peak load. The values that appears in each of the charts for Plans A and B, and other sections of the report are theoretical and do not assume this cap applies for this study.

3.3 Steady-State Analysis

The solar forecast and capacity allocation provides data needed to conduct feeder modeling analyses and to project solar capacity system-wide. These analyses are structured to quantify the impacts of solar DG on DVP's distribution system via steady-state load-flow studies and later in Section 3.4, via dynamic modeling techniques. The analysis includes evaluation and optimization of circuit and substation loadings consistent with DVP operational limits and requirements, as follows:

- Steady-state analysis
 - Impact of solar DG on transmission and distribution (T&D) equipment loading and performance
 - Aggregate limits or size restrictions of DG based on capabilities of typical T&D equipment
 - Sizing and control of facilities for bi-directional power flow
- Dynamic analysis
 - Operational and dynamic issues associated with solar DG MW penetration
 - DG MW penetration thresholds to identify the potential for operational and dynamic stability issues

The analysis identifies system upgrades and mitigation solutions that are needed once critical solar capacity threshold levels have been identified. The upgrades identified in this analysis should be treated as essential but not necessarily sufficient upgrades. Because this study is deterministic, based upon a limited set of feeder conditions, additional upgrades may be required to address alternative solar DG forecasts and allocation, both at the system and feeder level. Further, as solar DG penetration increases, recommended actions include but are not limited to both passive solutions (i.e., no active control) and the potential role of emerging technologies. Proposed mitigation solutions recognize DVP criteria such as safety, reliability, and upgrade costs. Feeder modeling focuses on the date and time of system peak solar output (typically during July at noon), and loading on each representative feeder at this date and time, which ranged from 30% to 60% of the feeder peak. Therefore, this analysis represents a spot check of anticipated forward-looking conditions as opposed to a full analytical assessment of all possible states or eventualities.

At the distribution level, solar DG impacts are derived based on analytical studies in accordance with DVP planning and operating standards and evaluation criteria. The distribution system analysis includes quantification of steady-state and dynamic impacts associated with the following criteria:

1. Overhead/Underground line/cable loadings do not cause overloads (net loading within normal loading limits)
2. Feeder primary and secondary voltages must remain within DVP limits (114 to 126 V)
3. Protection system impacts must be addressed through mitigation, including mitigation of two-way power flows on the primary distribution system, where applicable
4. Upgrades and options to mitigate solar DG impacts based on current technologies and solutions, e.g., no active inverter control via an ADMS

The following presents the strategies considered to mitigate solar impacts, and their associated cost. Options are prioritized based on those most commonly deployed by DVP, moving to more expensive options only when lower cost options prove unsuccessful.

3.3.1 Simulation Model

To quantify DG impacts on DVP's primary distribution system, Navigant evaluated solar impacts via Synergi simulations for each representative feeder, and then extrapolated these results to each feeder where new DG capacity is forecast to be installed. Synergi is a software platform that enables load-flow simulations, and it was used in this study to conduct feeder load-flow simulation analysis for each representative feeder.²³ The DG distribution system impact analysis includes a parametric impact analysis for increasing amounts of solar DG capacity on DVP's primary distribution system.

Specific steps undertaken to conduct the distribution impact analysis included the following:

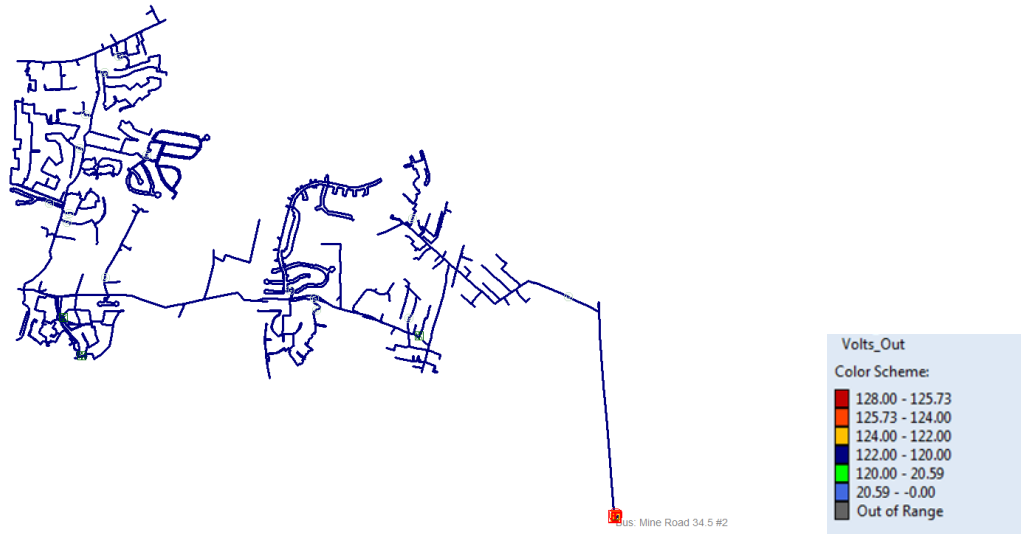
- Verification of Synergi software platform databases for 14 representative feeders provided by DVP Distribution Engineering
- Aggregation of solar capacity at feeder model nodes, or locations based on line segment loading and customer density
- Analysis of impacts via Synergi by increasing amounts solar DG capacity (0 MW to 30 MW on 34.5 kV feeders)
- Development of cost equations that predict integration cost as a function of increasing solar DG capacity for each representative feeder.

Figure 3-8 illustrates a typical feeder configuration as modeled in Synergi. This simulation does not include solar DG. Therefore there are no thermal or undervoltage or overvoltage violations. Figure 3-9 and Figure 3-10 illustrate the same feeder with 15 solar DG injection points, modeled as inverter-based, fixed power/fixed voltage generators. At higher solar DG penetration, 15 MW (50% of feeder rating) and 30 MW (100% of feeder rating), respectively, there are now thermal or voltage violations. The normal operating range for voltage in the DVP network must be maintained between 114 V and 126 V, which corresponds to 0.95 and 1.05 per unit. Furthermore, it is a DVP operating policy that interconnecting DG units cannot vary voltage on any feeder segment by more than 3% from its original pre-connection level.

Figure 3-9 and Figure 3-10 show the condition of the feeder without necessary upgrades to mitigate these violations. The case was simulated at peak solar output and noontime summer loading conditions. The higher voltages caused by solar DG appear in the figures as orange, red, or brown feeder segment, in increasing voltage. The blue feeder segments in Figure 3-8 represent normal operating voltage.

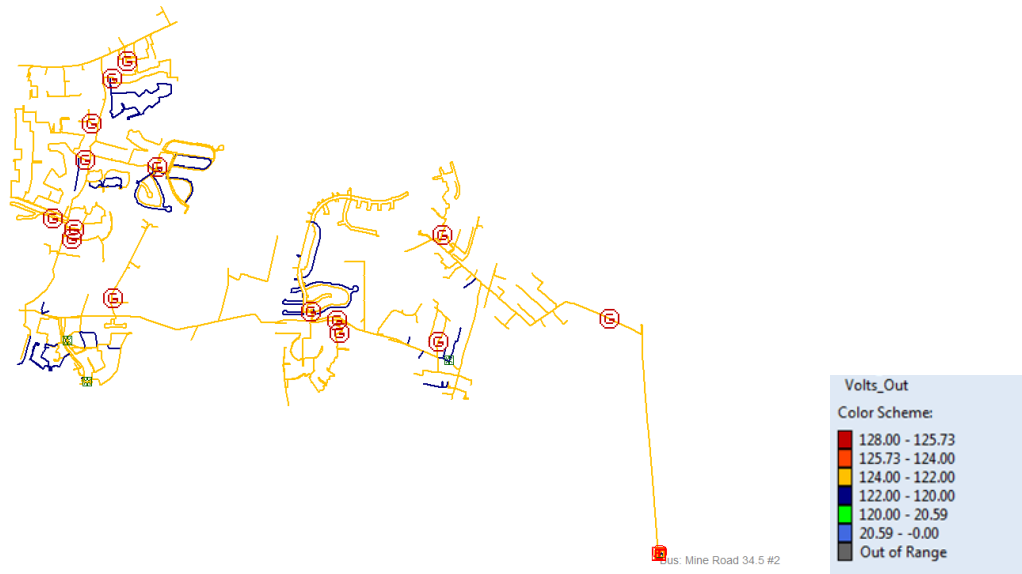
²³ Navigant obtained Synergi model databases for each representative feeder from DVP and conducted an independent analysis of solar impacts.

Figure 3-8. Typical Synergi Feeder Model with 0% Solar DG Penetration (0 MW)



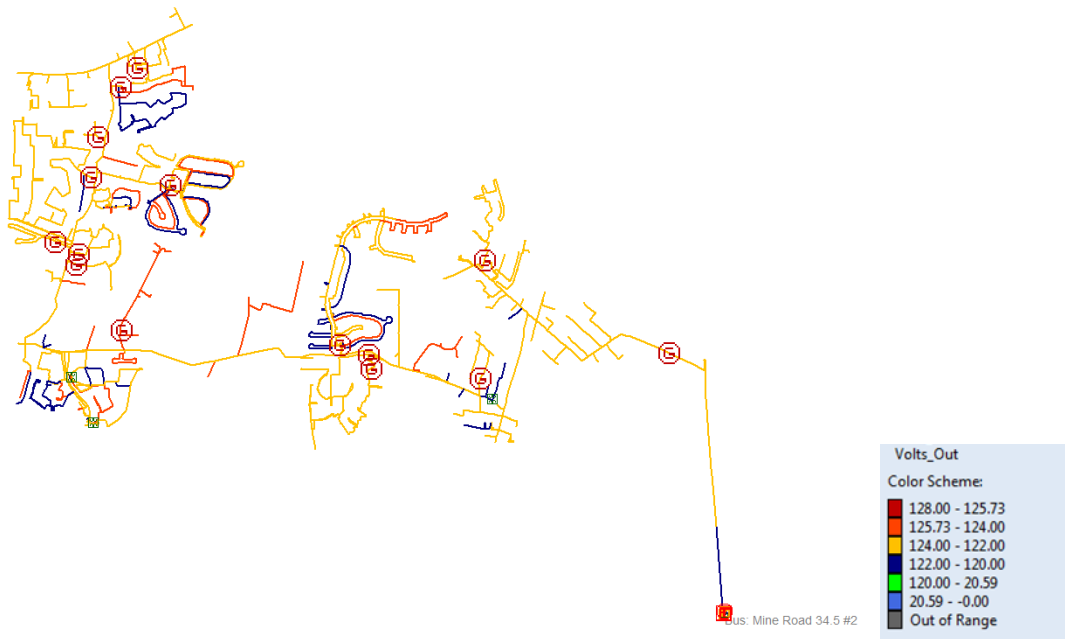
Source: Navigant

Figure 3-9. Typical Synergi Feeder Model with 50% Solar DG Penetration (15 MW)



Source: Navigant

Figure 3-10. Typical Synergi Feeder Model with 100% Solar DG Penetration (30 MW)



Source: Navigant

Solar DG capacity is allocated to each of the representative feeders based on DG classification and size. Two categories of DG are used in the allocation process for the hypothetical feed-in points on feeder. The first is small DG (NEM), defined as below 1 MW and below. For small DG, solar capacity is allocated based on the number of customers per rate class and respective electric load on each feeder segment. The second is large DG, or all solar units between 1 MW and 20 MW. For the latter, DG is assigned to specific locations on the feeder based on the presence of large industrial or commercial loads, or suitability of the feeder to accommodate large DG (e.g., availability of three-phase distribution lines). For small DG, solar capacity is aggregated and assigned to a single point source on individual feeder sections. For large DG, each solar device is assigned a specific location on feeders, typically about halfway along the main 3-phase feeder segment. About 70% of total solar capacity is assigned to NEM DG; 30% to large DG. Typically, 6 to 15 locations for solar injection is sufficient to accurately represent solar in the distribution load-flow model. Note that results can vary greatly depending on the location, size, and aggregation assumptions of the solar installations on the feeders; particularly if solar capacity is clustered near the end of the feeder.

3.3.2 Critical Level of Solar Capacity

For each solar DG MW capacity level, a determination is made as to whether thermal loading, voltage, or operational limits are violated, and the upgrades estimated to mitigate these impacts. The objective is to identify the least-cost option among those outlined in Section 3.3.4 to address the violation.

Navigant conducted simulation analyses to identify the level at which incremental solar DG MW capacity first creates violation of voltage limits, feeder ratings or operation constraints. When violations are identified, the lowest cost solution is selected to mitigate the constraint or violation. Further simulations were required to determine the applicability and effectiveness of potential solutions.

Hosting capacity is the maximum amount of solar DG MW capacity a feeder can accommodate before upgrades are required. Navigant's assignment of hosting capacity²⁴ is based on a combination of both smaller distributed solar and a few larger units distributed throughout the feeder where solar DG is most likely to be installed, illustrated in Figure 3-9 and Figure 3-10. The amount of NEM DG at any single location is based on the number of residential and small commercial customers located on feeder line segments. A single large DG equal to about 30% of total solar capacity is located about halfway down the main line feeder segment.

Although it is convenient to define hosting capacity as a single value based on the above solar capacity allocation, it actually varies according to the location and type or size of capacity installed. For example, feeders with most DG installed near the end of line segments typically will have less hosting capacity than if DG is installed close to the substation. Similarly, the size of DG units is important, as the impact is greater and hosting capacity typically is lower for larger units in a few locations compared to many smaller units distributed evenly across the entire feeder. The specific location and type or size of capacity installed can also impact the level of actual integration costs.

For purposes of the study, the assignment of solar capacity and determination of hosting capacity is first identified for each of the 14 representative feeders described earlier by increasing solar DG capacity proportionally at each feed-in node until thermal or voltage violations are detected via steady state load-flow simulation analysis.²⁵ Supplemental dynamic analysis is also performed in Section 3.4 for a subset of feeders to address protection, operational, and power quality issues that may not be fully represented in the steady-state analysis, each of which may result in downward adjustments in the amount of solar capacity that can be installed before a state of criticality is reached.

3.3.3 Integration Options

Navigant developed formulas (cost equations) for each representative feeder to predict system upgrade cost as a function of solar DG MW capacity, developed by conducting Synergi load-flow simulation studies for DG capacity levels ranging from 0 to 30 MW (0 to 100% of the maximum MW feeder rating). The point at which solar DG capacity results in voltage, loading or operational violations defines the lower boundary of the cost curve (i.e., all solar DG capacity below this threshold produces zero system upgrade cost). The cost curves are derived based on the cost of mitigating each violation, the cost of which usually increases as a function of solar DG MW capacity. These cost curves do not include line extensions, protection, automation, and control costs associated with physically connecting solar onto the grid. These costs are derived separately from system upgrades described herein.

The cost to mitigate solar capacity impacts on the primary distribution level included substation and feeder upgrades. In some cases, new equipment is installed when existing lines and substations are incapable of interconnecting solar. Virtually all candidate distribution upgrades use currently available technology, as enabling technologies at the distribution level may not be commercially available until several years into the study (addressed in the Emerging Technologies section of the report).

The following options were considered to identify solutions to mitigate impacts and to calculate system upgrade costs at the distribution level. These options are typically those applied by utilities to address

²⁵ For each feeder type, supplemental analysis is also performed in the dynamic studies to address protection, operational, and power quality issues that may not be fully represented in the steady-state analysis, each of which may result in downward adjustments in the amount of solar capacity that can be installed before a state of criticality is reached.

steady-state or transient impacts. The first two items on the following list are traditional capacity upgrades, usually through replacement of existing equipment with higher rated devices.

1. New or upgraded primary overhead/underground line/cables (overloads)
2. New or upgraded substations (including transmission supply lines)
3. Equipment replacement, including line transformers for secondary line impacts
4. Feeder voltage and reactive support (regulating devices or upgraded lines)
5. Protection system upgrades (including mitigation of two-way flows)
6. Operational-related upgrades (improved tie transfers)

3.3.4 System Upgrade Costs

As solar DG penetration levels increase beyond hosting capacity limits, mitigation in the form of system upgrades is required. Table 3-6 illustrates this concept for representative Feeder11. At solar penetration levels of 4.5 and 7.5 MW (15% and 25% of maximum feeder rating), no mitigation is necessary, and 7.5 MW is the assigned hosting capacity. Above 7.5 MW (>25% of maximum feeder rating), mitigation of solar impacts is required at increasing amounts. For example, at 15 MW, 3.7 miles of overhead line is reconductored; at 22.5 MW of solar DG, 5.6 miles of overhead line must be reconductored to maintain line loadings or voltage levels within prescribed limits.

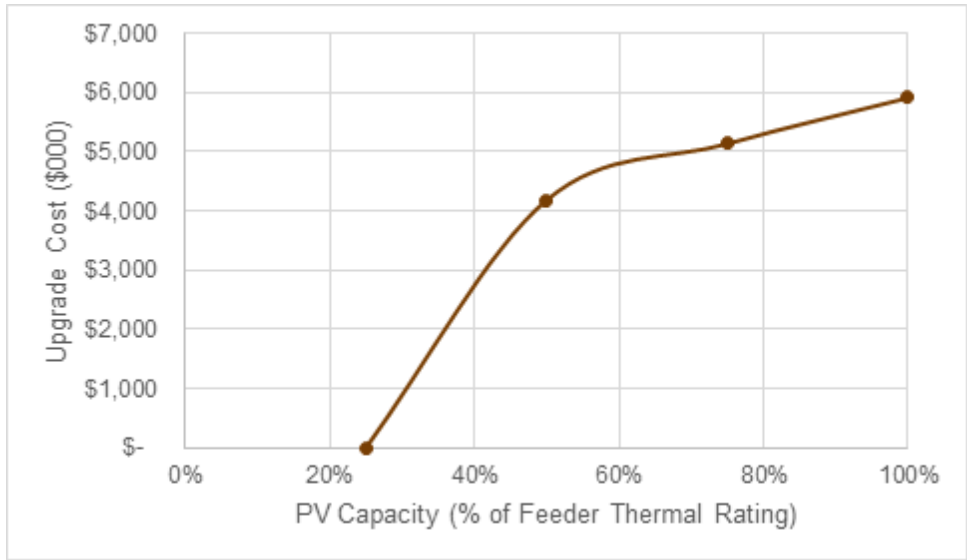
Table 3-6. System Upgrades Necessary for Increasing Solar DG for Representative Feeder #11

Solar DG Penetration	0 MW 0%	4.5 MW 15%	7.5 MW 25%	15 MW 50%	22.5 MW 75%	30 MW 100%
Mitigation Steps	None	None	None	1. Reconductor 3.7 mi of OH line 2. Reconductor 1.4 mi of UG line 3. Add 2 phases and fuses; and balance load for 1.4 mi of UG line	1. Reconductor 5.6 mi of OH line 2. Reconductor 1.4 mi of UG line 3. Add 2 phases and fuses; and, balance load for 1.4 mi of UG line	1. Reconductor 5.6 mi of OH line 2. Reconductor 1.4 mi of UG line 3. Add 2 phases and fuses; and, balance load for 3.3 mi of UG line

Source: Navigant

Navigant was provided generic unit cost estimates for each mitigation option by DVP. Using these estimates derived from load flow simulation analysis, Navigant estimated the cost of system upgrades at each solar DG capacity level each representative feeder. Figure 3-11 shows the cost curve for representative Feeder 11.

Figure 3-11. Steady-State System Capacity Upgrade Cost Curve for Representative Feeder 11



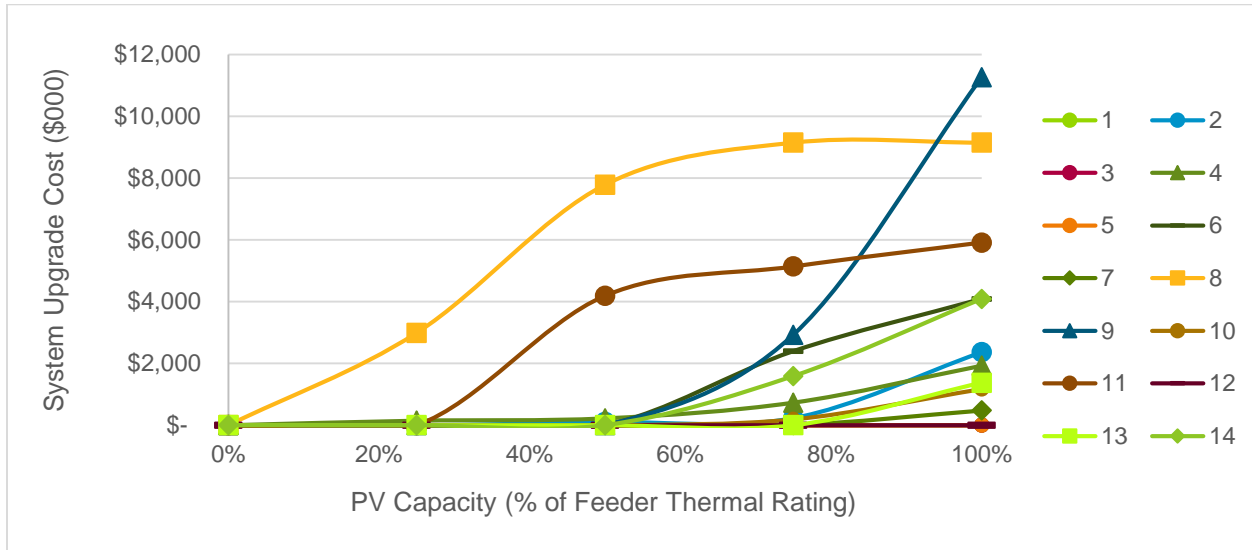
Source: Navigant

3.3.5 Solar DG System Upgrade Cost Curves

The parametric analysis of solar capacity on the representative feeders identifies how system upgrade costs vary as a function of solar capacity once the hosting capacity threshold is reached. The values obtained for each representative feeder is then applied to all other feeders within each cluster to predict total system upgrade costs for the entire DVP distribution system.

Figure 3-12 presents the system upgrade cost curve for each of the representative feeders - an example of the mitigation steps selected to generate the curves is shown in Table 3-6. Results indicate that system upgrade costs vary significantly among representative feeders, primarily due to differences in voltage and line loadings.

Figure 3-12. Steady-State System Capacity Upgrade Cost Curves for Representative Feeders



Source: Navigant

Figure 3-12 demonstrates that some representative clusters incurred high costs at lower penetration levels, namely Cluster 8 and Cluster 11. Furthermore, the highest cost circuit at 100% penetration was the Cluster 9 representative. While all three representative feeders are fed at 34.5 kV, they have significant lengths of low-voltage line sections (13.2 or 4.16 kV), plus single-phase lines, and are generally more lightly loaded per mile of line than other representative feeders. This information is shown in Table 3-7.

Table 3-7. Comparison of Significant Properties of High-Cost Feeder Clusters

Cluster	1	2	3	4	5	6	7	8	9	10	11	12	13	14	Comment
Load/Length (kW/mi)	644	375	934	247	301 5	70	541	143	115	305	191	492	277	339	Lower values indicate greater mitigation is required
% 1 Phase Line	40%	71%	14%	41%	2%	77%	56%	60%	77%	76%	59%	30%	72%	75%	Higher values indicate greater mitigation is required
Miles of <34.5 kV Line	0.0	15.0	0.0	3.8	1.1	50.9	1.1	22.1	38.2	11.7	15.7	8.0	0.9	19.2	Higher values indicate greater mitigation is required

Note: The "high cost" representative feeders are shaded with a light grey background.
Source: Navigant

Feeder properties are predictors of mitigation strategies as the majority of violations encountered were on low-voltage, small-gauge, single-phase conductors. For example, Clusters 2 and 4, which are 13.2 kV and 4.16 kV respectively, encountered overvoltages or overloads at all solar penetration levels.

3.3.6 Solar DG Critical Levels

By leveraging the preceding analysis, Navigant estimated critical levels of solar DG by DVP zone. Table 3-10 presents hosting capacities for each of the representative feeders. Feeder hosting capacity is larger on feeders consisting of mostly high primary voltages.

Table 3-8. Critical Solar DG Levels of Representative Feeders

Cluster	Representative Feeder	Primary Voltage (kV)	Low/High-Voltage Ratio	Hosting Capacity (MW)
1	25360	34.50	0.00	30
2	26771	13.20	0.00	3
3	46366	34.50	0.00	30
4	21575	4.16	0.00	0
5	01600	13.20	0.00	11
6	06431	34.50	0.36	15
7	46780	34.50	0.06	22
8	67326	34.50	0.75	0
9	84345	34.50	0.97	15
10	43419	34.50	0.25	22
11	81368	34.50	0.38	7
12	25726	13.20	0.00	11
13	42478	34.50	0.02	22
14	25467	34.50	0.88	15

Source: Navigant

3.3.7 Distribution System Benefits

Navigant evaluated the applicability of the following potential distribution benefits:

1. Substation and feeder capacity deferral, including conditions under which firm capacity can be assigned to solar DG for radial lines and given intermittent output
2. Reduced distribution losses
3. Improved feeder regulation and power factor (via inverter control)
4. Enhanced reliability

All benefits evaluated are those that directly affect the utility; no external, customer, or societal benefits are assigned in the analysis. The primary distribution benefits considered include deferred feeder and substation capacity, line and equipment losses, reliability, and voltage benefits.

Distribution capacity benefits were excluded due to several factors, including non-alignment of solar generation with feeder peaks and variable solar output. Navigant assumed that any capacity benefits are predicated on solar providing the same level of reliability as traditional feeder upgrades, which typically operate at 99.99% availability or higher. Absent coupling of energy storage, physical assurance or demand response, solar DG is unable to meet this threshold. For example, energy storage matched with solar (addressed later) could provide a level of assurance to enable distribution planners to rely on solar as a firm capacity resource.

Due to the limited commercialization of smart technology needed to manage solar operation and the absence of standards for advanced inverter controls, enhanced reliability stemming from solar is limited. The presence of solar DG capacity does not reduce the frequency of customer interruptions or the duration of interruptions. Active voltage support from small PV inverters is anticipated over the next several years, but has not been implemented today beyond pilot evaluations.²⁶ Passive voltage support is included as a mitigation options for large PV inverters, with overvoltages mitigated via power factor adjustments. Thereby, avoiding more costly upgrades such as line reconductoring and voltage regulating devices. It also provides benefits from a voltage regulation perspective, as it can absorb or produce reactive power to address conditions such as overvoltages on lightly loaded lines with high solar capacity.

Absent enhanced smart technologies not generally available today, enhanced reliability stemming from solar DG, an intermittent resource, is very limited. It is possible to reduce the duration of interruptions via automated transfer schemes, where greater amounts of load could be transferred to non-faulted line sections. However, this scheme is feasible only for highly automated transfer schemes with centralized intelligent systems that monitor, track, and control DG. These schemes generally are not available today.

3.4 Dynamic Analysis

Solar DG capacity also may cause unacceptable voltage performance under non-steady-state conditions, commonly referred to as dynamic or transient conditions. It includes rapid voltage rise caused by intermittent solar output, typically due to rapidly moving cloud cover, or overvoltages during switching operations. A separate analysis was performed to study short-term impacts and changes in solar output over short time intervals, to better understand the impact of variable solar output on feeder voltage

²⁶ Several inverter suppliers include the capability to provide reactive support via adjustable power factors. Some utilities surveyed require this feature for larger inverters.

performance. This includes the rate of change both prior to and after operation of voltage regulating devices. Current DVP standards limit short-term voltage rise or drop (e.g., flicker) to no more than 3%.

The analysis was structured to compare dynamic impacts to those observed at the steady-state level. Representative feeders were screened by Navigant and DVP to identify candidates for further analysis. The selection process involved reviewing interconnection requests on representative feeders (i.e., pending requests for large amounts of solar), and feeder properties such as primary voltage and length. Based on the review, Navigant and DVP selected representative feeders for dynamic simulation analysis, as listed in Table 3-9.

Table 3-9. Representatives Used for Dynamics Analysis

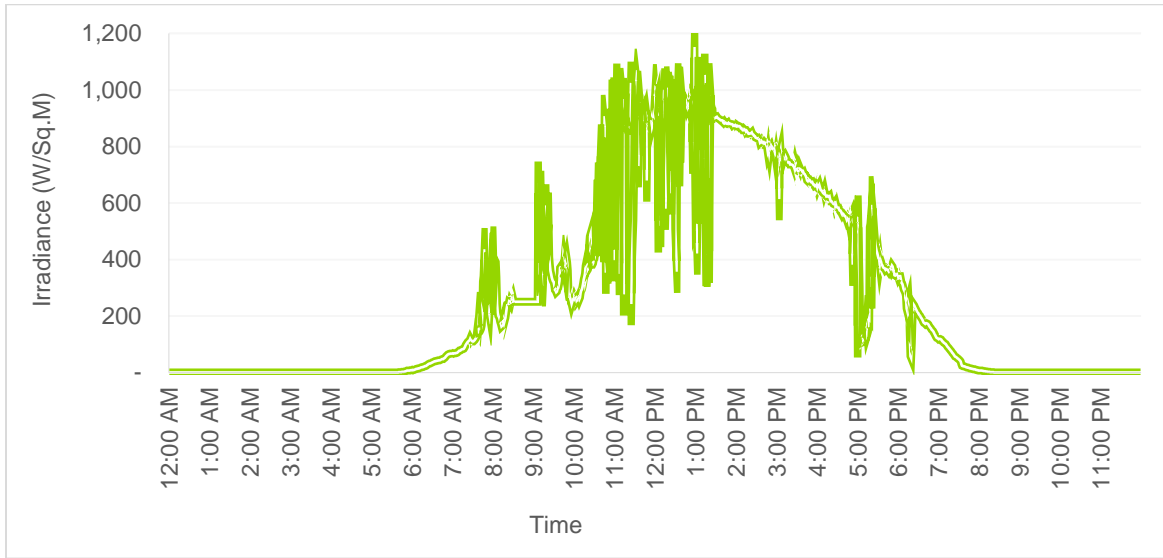
Cluster	Representative Feeder	Primary Voltage (kV)	Secondary Voltage(s) (kV)	Low/High-Voltage Ratio*	Hosting Capacity (MW)
3	46366	34.50	N/A	0.00	30
6	06431	34.50	13.2/4.16	0.36	15
12	25726	13.20	N/A	0.00	11

Source: Navigant

Navigant evaluated solar impacts at the same integration intervals (25, 50, 75, and 100% of feeder capacity) and interconnection points as those used in the steady-state analysis.

The time-series analysis module of Synergi is capable of analyzing the distribution system performance at 1-second intervals, and variances in load and generation were evaluated at this time step. The Synergi model applies global irradiance data to create smooth, hourly solar profiles via interpolation. The user then selects a linear shift in irradiance for successive time points by altering the output of the solar generators. Irradiance profiles provided by DVP were recorded at 15-second intervals in 2015 for Kitty Hawk, North Carolina and used as a proxy for sites in Virginia. Figure 3-14 illustrates irradiance data for July 15, 2015 at per-minute intervals.

Figure 3-13. Per-Minute Kitty Hawk Irradiance Profile (July 15, 2015)



Source: Navigant analysis of DVP data

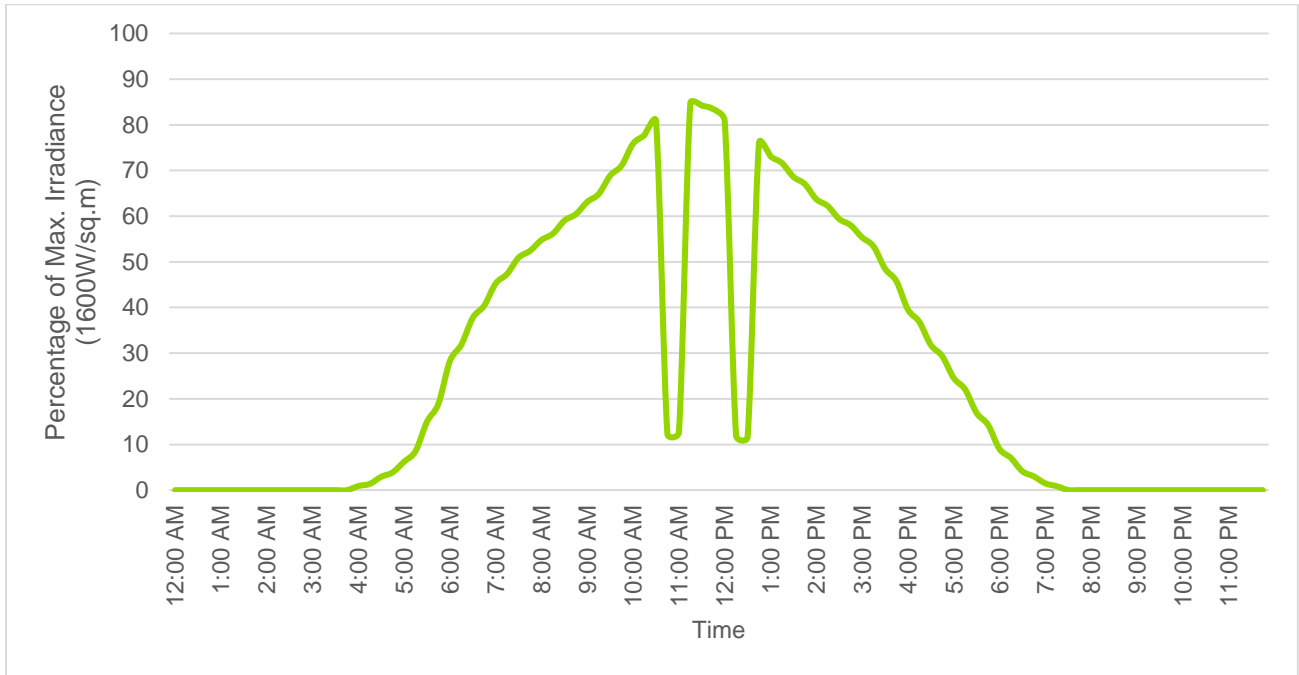
To determine worst-case impacts, Navigant developed 24-hour solar profiles for days exhibiting maximum hourly irradiance, June through August. Dynamic performance was examined for peak and minimum loads recorded during this interval.

Two key drivers of dynamic response and performance not captured in the steady-state analysis include short-term intermittency, caused by rapid variations in the irradiance profile, and longer-term generation versus load imbalances. Changes in solar output may cause voltage regulators to adjust feeder voltage upward when solar output decreases. When solar output returns to normal levels, feeder voltage can rise above operating limits during the interval before the regulator responds, due to time delay settings (typically 60 to 120 seconds).

The impact of intermittent solar output was modeled utilizing Synergi’s “Cloud Cover” module²⁷. Two types of cloud intermittencies were examined (frequent and infrequent). Figure 3-15 and Figure 3-16 show how the hourly irradiance profile was altered in each scenario.

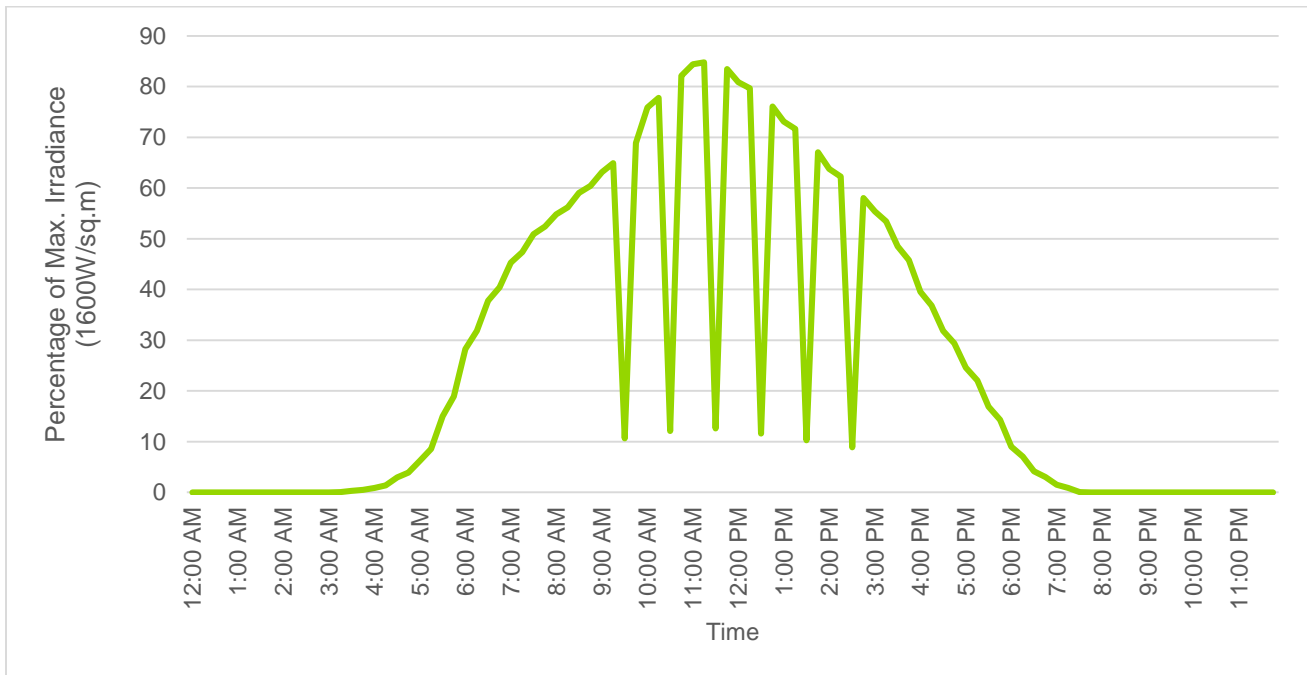
²⁷ When defining weather zones in Synergi, the user defines a threshold for irradiance levels that triggers a drop in irradiance to simulate the behavior of cloud cover and impact on feeder performance. The user can define the duration of cloud cover (seconds), the average gap between intermittent cloud events, the ramp rate of irradiance when a cloud event occurs, and the minimum irradiance during a cloud cover event. These parameters can be varied to produce different scenarios (i.e., short duration and frequent shading vs. long duration and infrequent shading).

Figure 3-14. Hourly Irradiance Profile with 30-Minute Cloud Cover



Source: Navigant analysis of DVP data

Figure 3-15. Hourly Irradiance Profile with 30-Second Cloud Cover

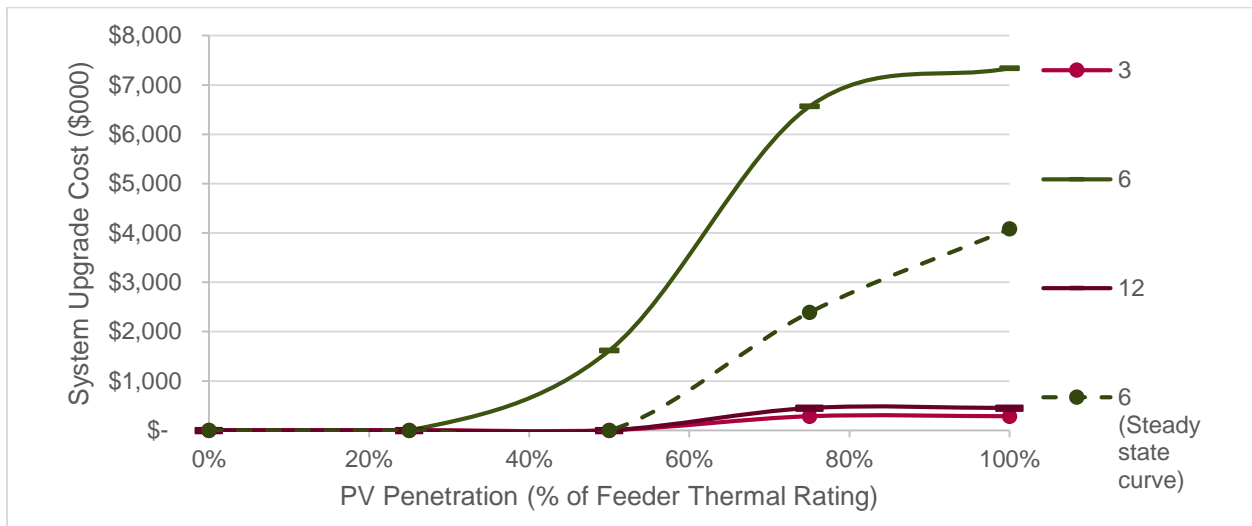


Source: Navigant analysis of DVP data

Only technologies capable of mitigating voltage transients during the time step were considered. For example, Navigant evaluated distribution STATCOM and fast-acting Lithium ion battery storage to mitigate dynamic impacts. Cost and feasibility of operation were primary factors in distinguishing the more favorable options for each feeder, and each were considered on a case-by-case basis. Operation of the devices is particularly significant, as the coordination of multiple STATCOM devices to mitigate transient overvoltage for several different line sections of feeders, in many cases, is a barrier to implementation. Navigant assumed a \$566/kW unit cost for ancillary services based on Lithium ion storage.²⁸

The resulting cost curves for each mitigation option are illustrated in Figure 3-17. All upgrades specific to dynamics impacts were made assuming implementation of previously recommended steady-state upgrades such as reconductoring or install of voltage regulating devices. The solid lines shows total cost of upgrades required to address dynamic impacts versus the dotted line, which shows costs to mitigate steady state impacts. Feeders 3 and 12 did not initially require steady state upgrades. Figure 3-17 indicates that hosting capacities of the studied feeders decrease when dynamic impacts are considered, with attendant higher system upgrade cost. All upgrades are needed for longer-term solar output variances, as rapid voltage variations >3% of nominal per minute were not encountered in any scenarios; maximum fluctuations are summarized in Table 3-13.

Figure 3-16. Dynamic Performance System Upgrade Cost Curves for Selected Clusters



Source: Navigant

²⁸ Navigant Consulting, “Energy Storage for the Grid and Ancillary Services” published Q3 2014.

Table 3-10. Maximum Short-Term Voltage Fluctuation Observed During Dynamics Analysis

Cluster	Representative Feeder	Maximum Voltage Fluctuation (% of Nominal/Minute)
3	46366	0.5%/minute
6	06431	0.65%/minute
12	25726	0.3%/minute

Source: Navigant

Representative feeder #6 in Figure 3-17 experienced voltage spikes, after overhead cloud cover dissipated, due to the time delay in regulator response. Accordingly, fast-acting battery storage was implemented on feeder sections with high voltage spikes. Further, steady-state voltages of these line sections needed to be decreased to further mitigate transient overvoltage. The cost to reconductor lines to mitigate these impacts is significant. In contrast, feeder #12 had a large steady-state generation load imbalance, which led to sustained overvoltages lasting a few minutes near peak solar output. In this case, the installation of a singular distribution STATCOM device (which as a single device did not trigger coordination issues) was sufficient to resolve this issue, and is generally more cost-effective today than energy storage devices designed to address impacts or operating requirements over a longer period of time. Upgrades for feeder #3 resulted from frequent action of the substation load tap changer (LTC), caused by rapid ramping of solar output due to rapid shifts in simulated cloud cover. In this instance, fast-acting storage is needed to smooth line voltages. However, storage for feeder #3 had lower capacity and operated for a shorter time period than the system implemented for representative feeder #6.

Simulation results for a subset of the representative feeders demonstrate that dynamic impacts may be a factor on other distribution feeders, particularly for high solar penetrations, and should be factored into any system planning.

3.5 Emerging Technologies

Higher penetration of solar can cause thermal and voltage violations, and application of emerging solutions can mitigate both steady-state and dynamic impacts. Further, use of energy storage can address performance impacts and provide capability for “firming” of solar resources for capacity deferral. Emerging technologies can help to address and mitigate impacts of higher penetration levels of solar DG. Advanced distribution technologies are highly dependent on the availability of high-speed telecommunication systems. In addition, the cost of upgrading current communications systems or new systems where none exist today may be prohibitive.

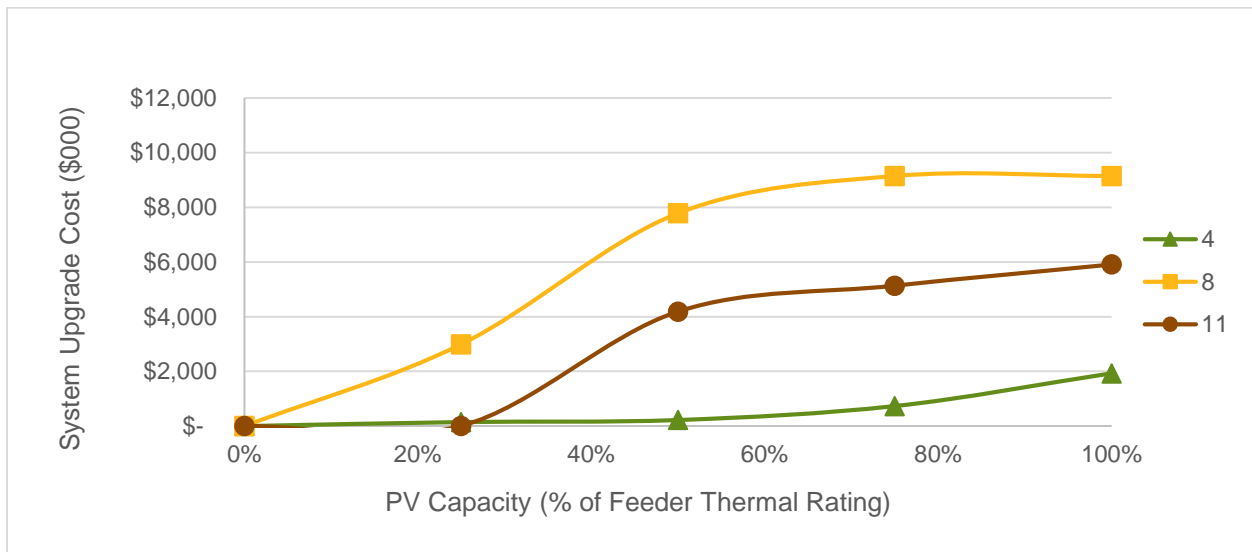
Navigant investigated the extent to which advanced inverters (specifically their capability to support voltage through power factor control) and battery storage could both be used to mitigate operational concerns in the DVP network. Two scenarios were developed where these technologies were implemented in favor of the traditional mitigation options considered in Section 3.3. The first scenario involved the deployment of only advanced inverters, while the second involved the joint deployment of battery storage and advanced inverters. A single storage unit was considered for deployment in the second scenario, at the point of connection of the solar DG with highest rating on the feeder.

No feeder specific costs are associated with the deployment of advanced inverters customers bear the cost of advanced inverters; however, their applicability in DVP’s network is predicated by system-level telecommunications and DMS investments, which are required, but whose costs are excluded from this

report. Since the cost of system-level telecommunications and controls are not assigned to any single PV owner, including NEM, the costs would be borne by DVP ratepayers.. Navigant has assigned a \$1944/kW unit cost for peak shifting, flow battery storage from its research report referenced in Section 3.4. This cost is represented in nominal 2016 dollars, rather than a projection for the probable year in which it might need to be installed.

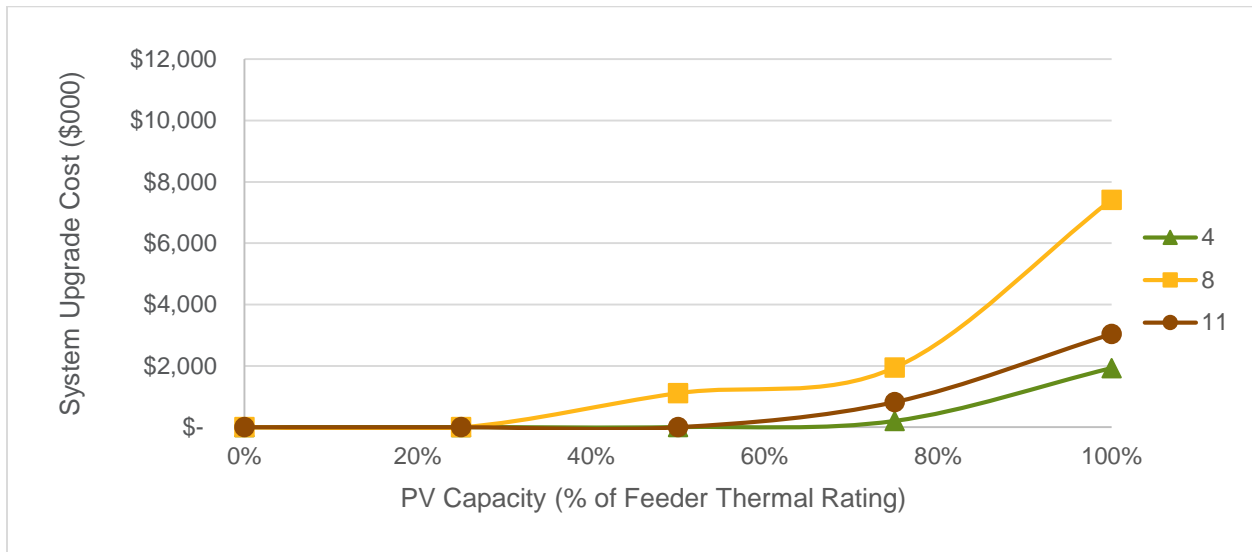
The cost curves for traditional mitigation options appear in Figure 3-18, and the revised mitigation costs for the two non-traditional upgrades appear in Figure 3-19 and Figure 3-20. Comparing Figure 3-18 with Figure 3-19 confirms a large decrease in costs occurs at lower solar penetration levels, when power factor control for voltage regulation is deployed. Hosting capacity (the highest penetration level that requires no upgrades) was increased for each feeder. The higher solar penetration levels still require additional traditional upgrades, in order to address other violations.

Figure 3-17. Traditional Mitigation System Upgrade Cost Curves for Selected Clusters



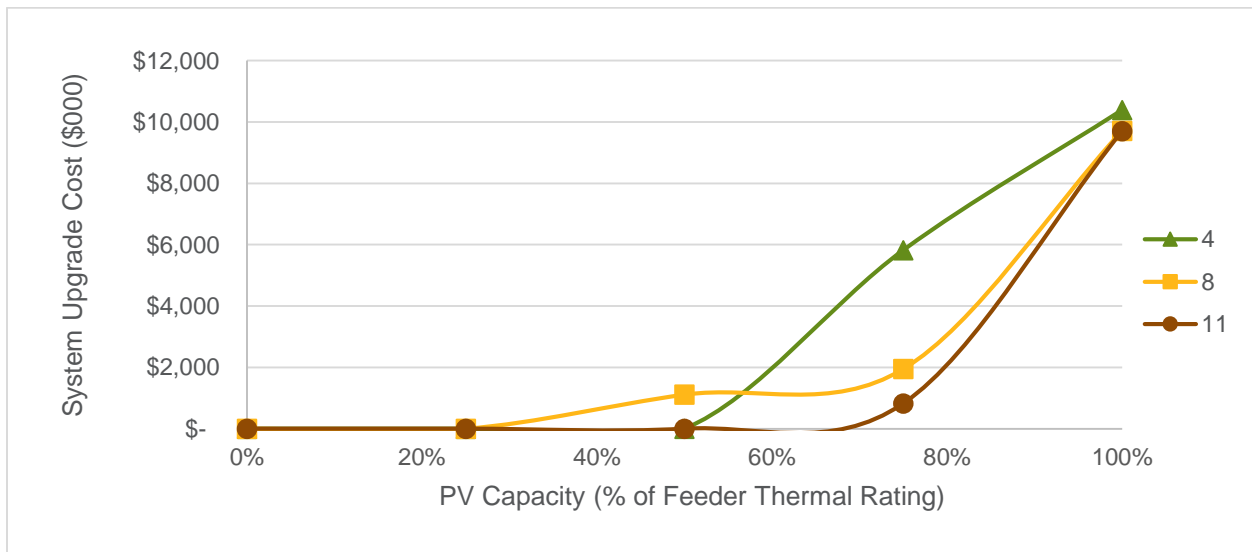
Source: Navigant

Figure 3-18. Advanced Inverter System Upgrade Cost Curves for Selected Clusters



Source: Navigant

Figure 3-19. Advanced Inverter and Storage System Upgrade Cost Curves for Selected Clusters



Source: Navigant

The cost curves generated by the second scenario are shown in Figure 3-20. Results indicate that implementing energy storage is effective at mitigating impacts, but is a more costly measure than other traditional options for the studied feeders. Mitigating sustained overvoltages at multiple feeder segments requires a high capacity battery capable of discharging for several hours (i.e., a peak shifting application). Other benefits associated with energy storage, such as energy arbitrage, ancillary services or peak shifting, may need to be considered for the energy storage investment to be competitive with other solutions.

4. FINDINGS AND CONCLUSIONS

This report presents Navigant's independent assessment of industry best practices for interconnecting DG to electric utility distribution systems, and solar DG impacts in DVP's Virginia service territory for increasing amount of solar DG capacity. This research effort evaluated solar DG capacity under a range of loading and operating conditions for DVP feeders located in Virginia. The study includes evaluation of higher solar capacities to determine the level at which a state of criticality is reached, defined as a condition for which solar impacts and the costs to mitigate these impacts become significant. All results were prepared using simulation tools and methods consistent with leading industry practices.

A key study finding is Navigant's determination that the hosting capacity on many distribution feeders, defined as the amount of solar capacity that can be installed without distribution system upgrades, is high on many DVP feeders. Feeders with lower hosting capacity tend to be at lower voltages or longer feeders with localized impacts. However, the solar scenarios studied herein assume solar is distributed throughout DVP's service territory with limited clustering along feeder segments. Increased clustering will cause system upgrade costs to increase. Further, as solar capacity increases above current levels, the cost to connect DG to DVP's system may be higher than prior averages to cover the additional cost of protection, communications, and controls that may be needed. These additional costs can be significant even when distribution system upgrades are not needed. This study includes connection costs based on historic DVP averages applied to all DG rated greater than 1 MW, and when all connected DG to a feeder, including NEM, exceeds 1 MW.

All estimated costs for distribution upgrades are based on present day capital spending and include only those incremental costs that directly affect DVP's distribution system. As noted in Section 3.3, while the study attempts to quantify the resulting cost impacts of increasing solar DG capacity on DVP's system, the cost figures reflected in the study exclude certain significant costs that may be beyond the narrow scope of this study but nonetheless are essential to assessing the true cost impacts of integrating solar DG into the Distribution System. For example, large aggregation of NEM DG may trigger the need for system upgrades, which are then absorbed into the utility distribution budget and funded by all ratepayers.

The study includes connection costs based on current averages, but excludes the cost of telecommunications infrastructure, automation and data management technologies, administrative, staffing, IT systems (e.g., billing, customer service, transmission and advanced distribution management systems) and overhead costs related to modifications and enhancements that will be required to integrate greater levels of solar PV into the distribution system, and which are not included in DVP's average connection costs for prior DG installations. Cost impacts detailed within the body of the Report relate only to the defined scope of work for this specific study and, as a result, provide only partial representation of total potential costs of solar DG integration.

Additionally, the solar integration costs actually vary according to the location and type or size of capacity installed. For example, feeders with most DG installed near the end of line segments typically will have larger integration costs than if DG is installed closer to the substation. Similarly, the size of DG units is important, as the impact is greater and integration costs are higher for larger units in a few locations, compared to many smaller units distributed evenly across the entire feeder. These estimates also exclude third-party, customer, or societal benefits or costs, which can also be significant.

Based on the above and the analysis contained herein, Navigant offers the following findings and conclusions:

1. Utility interconnection practices and policies vary among the utilities surveyed and Navigant experience
 - A. Anti-islanding limits and tie transfer limits vary widely
 - B. Most utilities require telecommunications and transfer-trip arrangements for agreeing to interconnect large DG projects
 - C. Protection practices vary widely, with some more stringent than others
 - D. All utilities require some form of DG isolation for scheduled or unscheduled outages
2. Most residential solar DG capacity additions are likely to be located in sections of DVP's service territory where housing value and income is highest
 - A. Areas with high solar DG penetration forecast include Richmond, Norfolk, and northern Virginia
 - B. System upgrade costs are highly locational. Some DVP zones experience above average system costs solely due to high DG penetration while other feeders incur higher average upgrade cost due to greater susceptibility to impacts caused by solar
 - C. System upgrades costs mostly include reconductoring and voltage regulation on primary distribution lines, both overhead and underground; secondary impacts and associated costs were excluded from the analysis
 - D. If large quantities of DG are installed on feeders with high system upgrade cost, total average cost per zone increases. Examples include Zones 363 and 364
3. The amount of solar capacity that DVP's system can accommodate varies depending on feeder voltage and DG size
 - A. Feeders operating at 34.5 kV can integrate higher levels of DG than lower voltage feeders and feeder segments
 - B. 4.16 kV feeders can accept far less solar capacity than 13 kV and 34.5 kV lines
 - C. Feeder limits may decrease when dynamic effects are considered
 - D. Feeders serving secondary and spot networks are likely unable to integrate the same amount of DG as radial feeders; additional analysis is needed to confirm this premise
4. The average cost to mitigate DG impacts, once feeder limits are exceeded, can be substantial on many feeders. The additional costs of communication and control systems needed to manage large quantities of solar can further increase cost
 - A. Distribution system upgrade costs increase at higher levels of solar
 - B. System upgrade costs can vary significantly for individual feeders
 - C. System upgrade costs are likely to increase, substantially for some feeders, when dynamic effects are considered
 - D. Additional study is needed to determine long-term communications and controls required for high solar penetration
5. Simulation results for a subset of three representative feeders confirms dynamic impacts can degrade feeder performance and significantly increase system upgrade costs, and likely to be a factor on other distribution feeders
 - A. The hosting capacity on the three representative feeders studied decrease and system upgrade costs increase when dynamic impacts are considered. Dynamic analysis should be

- conducted for a larger set of feeders to confirm impact and cost for a broader range of operating and loading conditions.
- B. Impacts are greater for high solar penetration levels and should be factored into DVP's planning for solar integration
6. Emerging technologies can enable greater amounts of solar capacity (i.e., hosting capacity) on many DVP feeders
- A. Energy storage proved very effective in mitigating solar impacts, when installed in capacities equal to about 10% of installed solar capacity
 - B. The cost of energy storage may not be competitive with other mitigation options
 - C. Active inverter control also proved effective in mitigating impacts and increasing solar hosting capacity for feeders experiencing voltage violations. The cost to implement and manage these systems could be substantial and may not be cost-effective.

The results of Navigant's research provide important findings addressing impacts of solar DG capacity, but these results are preliminary. In order to better understand solar integration costs for the transmission and distribution network, additional analysis and research should be completed. This analysis should include, but is not limited to, the following factors:

1. Increased clustering of DG capacity within DVP zones (steady state and dynamic impacts);
2. Additional dynamic analysis under a range of operating and loading conditions;
3. Stability analysis of high penetration DG to supplement dynamic study findings;
4. Tracking and monitoring of industry research and tools designed to assess harmonic impacts of large penetration of solar on feeders and systems comparable to DVP;
5. Evaluation of an expanded set of emerging technologies, including other storage options and control strategies;
6. Detailed evaluation of distribution management, telecommunications and control systems to mitigate impacts and enhance benefits;
7. Administrative cost, including new business processes and support systems that may be needed to manage interconnection applications, billing and tracking for large quantities and high penetration of solar; and,
8. Impact of energy storage, other DG technologies and demand response when combined with the solar scenarios evaluated in this research effort.

APPENDIX A. UTILITY SURVEY

A.1 DG Integration Survey

The following questionnaire is designed to create a framework for integrating solar DG onto an electric utility's distribution system. It is designed to enable electric utilities to safely and reliably interconnect solar DG capacity. Results from the survey will be combined with findings from industry standards, utility best practices, and outside research to develop a roadmap documenting best practices relating to DG integration.

There are six categories of questions, each relating to different aspects of DG interconnection and integration to an electric utility's distribution system. The first set of questions request general information on existing DG capacity and interconnection requirements. The next five categories address interconnection applications and practices. For purposes of this survey, DG is defined as the maximum capacity that can be interconnected directly to the distribution system or substation (low-side bus). All references to DG is for solar photovoltaic ("PV") systems.

(1) General Questions

- How does your utility define "distributed generation"?
- What is the total installed DG capacity on your system? What is the system peak?
- Of the above, what amount of DG is behind the customer meter versus directly connected to the primary distribution system?
- Approximately, how many applications for DG interconnection were received in 2014?
- Has your State implemented Net Electric Metering (NEM)?
- If yes, what is the maximum NEM capacity limit?
- Is there a total NEM capacity limit in your State or utility? If yes, is there a sunset date (please indicate year)?
- Is there an individual or group within your company solely responsible for responding to interconnection requests and impact evaluation? Please provide contact information.
- Can you please share a process map outlining the overall internal workflow?

(2) DG Interconnection Process

- Does your company offer or plan to offer a web-based platform that Applicants can use to evaluate or apply for Interconnection Requests?
- If yes, please provide response to the following questions:
 - Is there a DG capacity threshold used to determine eligibility for interconnection for web-based applications? If yes, what criteria or methodology does your company use to set the capacity threshold?
 - Does your utility provide web-based maps that provide an indication of available distribution interconnection capacity for potential Applicants? If yes, is available DG interconnection capacity available for individual circuits, by line segment or substation bus?
 - In addition to collecting applications, does the platform help to manage the internal interconnection processes as well (e.g., track deadlines, send automatic updates to the applicant)

- What software platform is used?

(3) Grid Protection: Technical Requirements for Interconnection

- Has your company taken a position or advocated use of a standardized solar photovoltaic (“PV”) model to represent the operating characteristics of PV inverters (to enable more accurate modeling of DG for interconnection and protection studies)? If yes, please summarize position taken, relevant concerns, and expected benefits.
- Has your company taken a position or advocated development of industry standards for PV controls and inverter technology? If yes, please summarize position taken, relevant concerns, and expected benefits.
- Has your company taken a position or advocated use of an industry standard for DG protection schemes? If yes, please describe.
- Please describe your company’s requirements for interconnection facilities, including generator step-up transformer winding configuration, grounding requirements and other requirements. Please differentiate between behind the meter and DG connected directly to the primary distribution system.
- Please describe your company’s requirements for open phase detection of DG interconnecting transformers.
- Please describe methods or requirements to detect and isolate faulty inverters on a circuit.
- Has your company limit DG capacity based on anti-islanding limits? If yes, please describe the criteria applied (e.g., no reverse power flow on main line or lateral line segments due to PV output).
- Has your company encountered and/or evaluated the impact of reverse power flows on voltage regulation equipment such as load tap changers? If yes, please describe the impacts (e.g., loading or voltage violations), if any, and mitigation applied to address the condition.
- Has your company encountered protection coordination issues due to the presence of multiple DGs or a combination of DG and traditional units connected to the distribution system? If yes, please describe the coordination issue, if any, and mitigation applied to address the condition.
- Please describe operational tests required to commission and approve operation of the DG (may be difference procedures based on DG size and total connected capacity).
- Please describe required maintenance requirements and maintenance intervals of interconnection equipment owned and operated by your utility or the DG owner.

(4) Operational Safety

- Has your company developed policies and procedures with respect to DG operation when work is scheduled (or unscheduled) on energized facilities? If yes, please provide separate responses, if applicable, when the work is performed on (1) the same circuit, (2) substation supply to the circuit, and/or (3) transmission lines connected to the substation.
- Has your company developed policies and procedures with respect to switching and line transfers that result in the transfer of DG from one source to another independent source? If yes, is re-energization allowed once the transfer to an alternate circuit or substation is made? Please describe methods employed to ensure re-energization or reconnection does not create loading or voltage violations, or operational concerns.
- For the above, if re-energization is allowed, does your utility use a Distribution Management System (DMS), in either automatic mode or semi-manual by Distribution Operators, to determine conditions under which transfer is allowed?

- Has your company developed policies and procedures with respect restoration procedures for T&D circuits that contain DG followed an interruption? Please describe these policies or methods used to ensure operational safety is not compromised by re-energization of DG.

(5) Circuit/Grid Stability

- Please describe methods or strategies your company uses to regulate voltage on distribution circuits with one or more DG.
- Please describe software simulation models used to conduct steady-state and dynamic studies for DG facilities on the distribution grid.
- Has your utility determined (via use of the above models) the amount of available capacity to interconnect DG (also referred to as hosting capacity)? If yes, has this been performed for the entire distribution system or on “as needed” basis to respond to interconnection requests?
- Have any applications for interconnection been denied or required to contribute to system upgrades due to transient impacts (e.g. voltage rise due to switching or loss of or rapid change in DG output)? Please describe any system upgrades required for interconnection.
- Has your utility encountered any impacts and/or made any adjustments for substations or circuits with DG on Frequency Load Shedding Schemes?
- For utilities with large amounts of installed DG, Has your company evaluated the impact of rapid varying output of inverters on grid stability (suitable ramp rates, curtailment of real power generation)? If yes, please describe findings.
- If applicable, please describe any coordination issues encountered during major system restoration when DG is located along the black-start cranking path.

(6) Communications & Data

- Please describe communications and systems used to monitor or control DG, and distribution devices and equipment.
- Please describe the organization(s) responsible for DG communications and monitoring (e.g. Distribution System Operations, DG Interconnections Group, System Protection).
- Please describe systems used for event analysis (resulting from DG operation).
- Please describe processes and systems used for data collection and validation of DG models.
- Please describe data inventory and reporting requirements for your utility and DG interconnection customer.
- Please describe communication systems used to monitor or control remote DG, and voltage regulation devices on distribution circuits.
- Please describe data management systems and solutions to collect, analyze and evaluate DG operations and impacts on the distribution system.

(7) Emerging Technology

(a) Energy Storage

- If different from solar interconnection requirements, please describe grid protection considerations for the interconnection of customer-owned energy storage systems.
- If different from solar interconnection requirements, please describe metering consideration for the interconnection of customer-owned energy storage systems.

- If different from solar interconnection requirements, please describe any operational requirements for the interconnection of customer-owned energy storage systems.
- If different from solar interconnection requirements, please describe the communications between the utility and PV site for transfer-trip or other protection needs to transfer signals between entities.

(b) Advanced Inverters

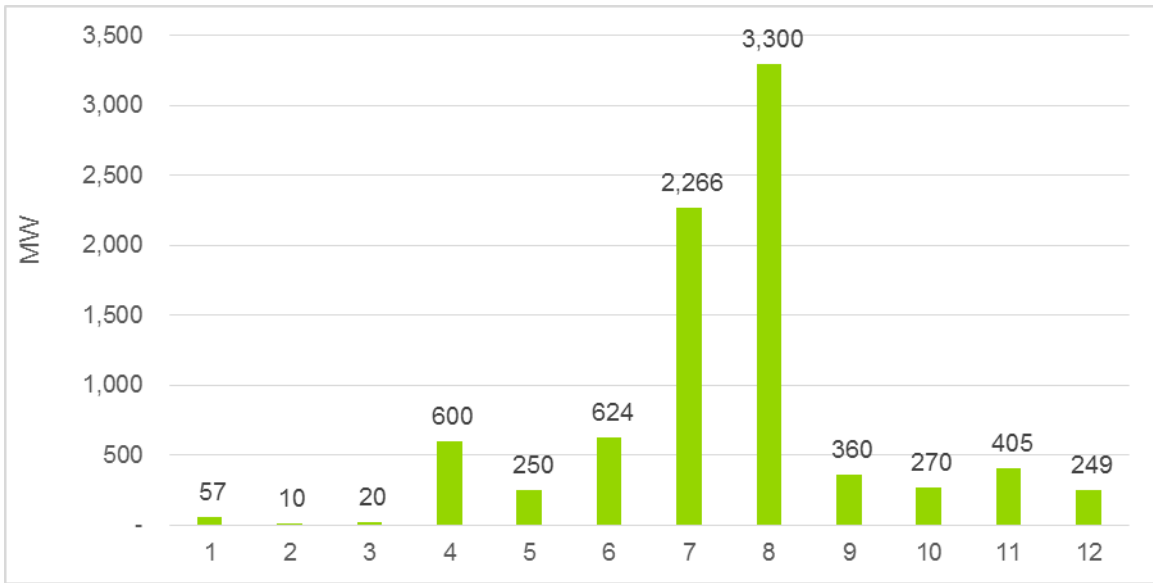
- Please describe existing or proposed applications of advanced inverter functionality, e.g., remote control, dispatching, and operator commands? Please describe how your utility plans to leverage these features and functionalities to mitigate issues such as steady-state overvoltage and transients, and operational requirements (e.g. tie transfers).
- Please describe how these features and functionalities are enabled or disabled when the inverter is customer-controlled vs. utility-controlled.

A.2 Survey Responses

All answers including quantitative data are illustrated in the figures below. For further information on qualitative answers, see Section 2.

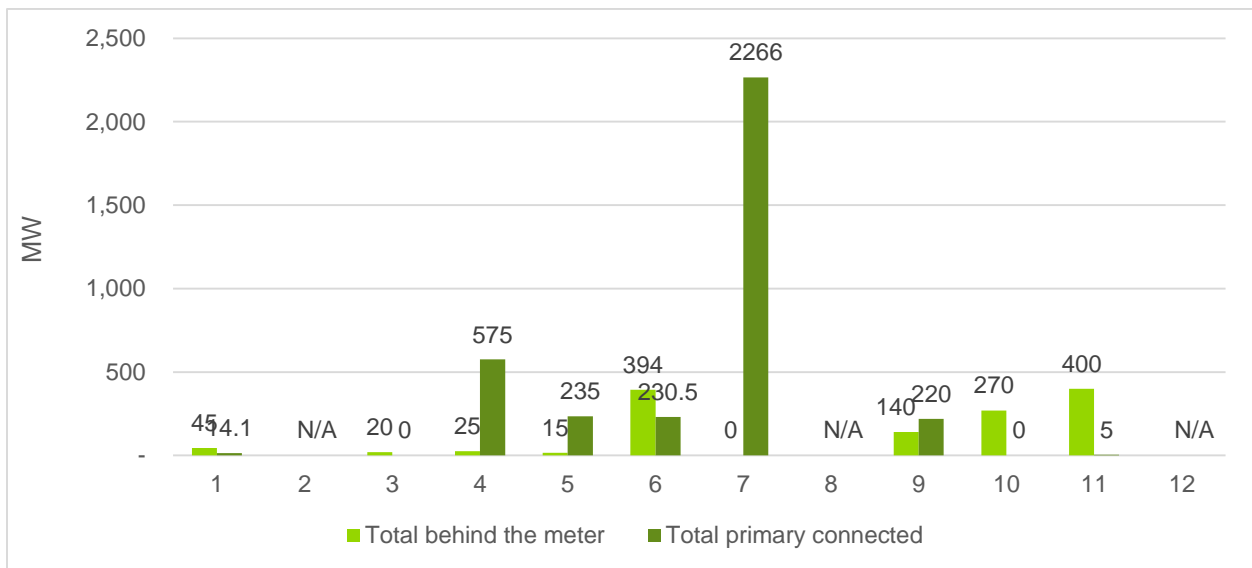
(1) General Questions

Figure A-1. MW of Installed DG by Utility



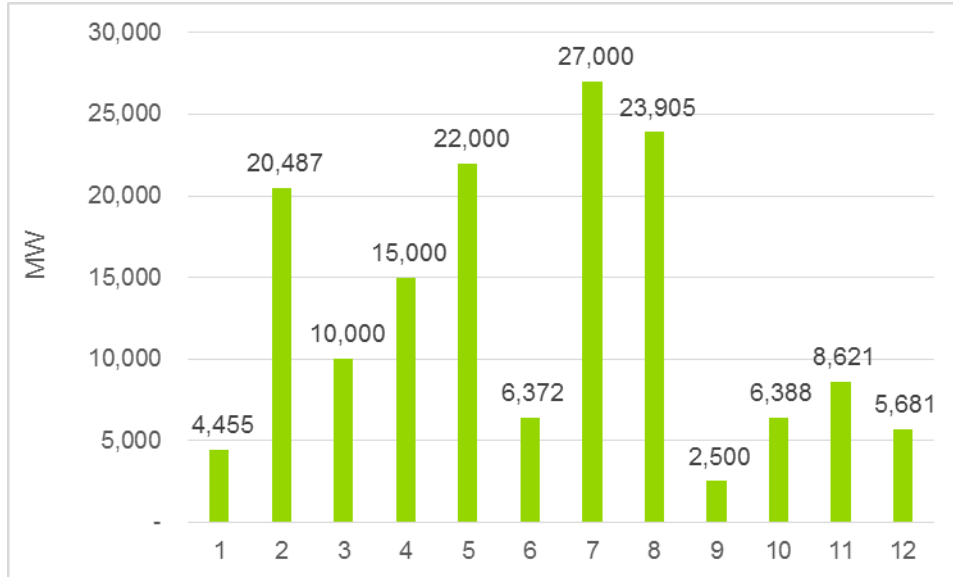
Source: Navigant

Figure A-2. MW of Behind the Meter vs. Primary Connected DG by Utility²⁹



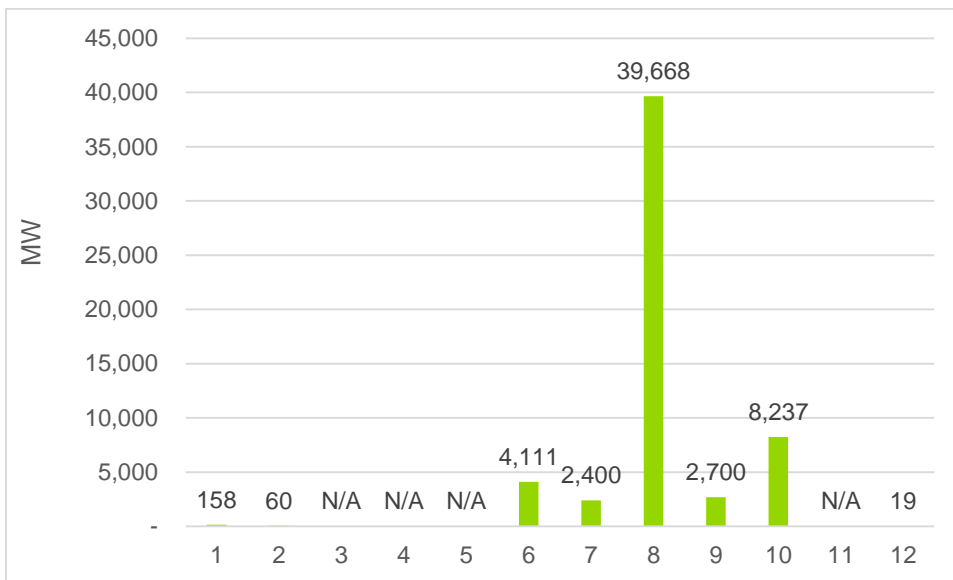
Source: Navigant

Figure A-3. Distribution System Summer Peak Load by Utility



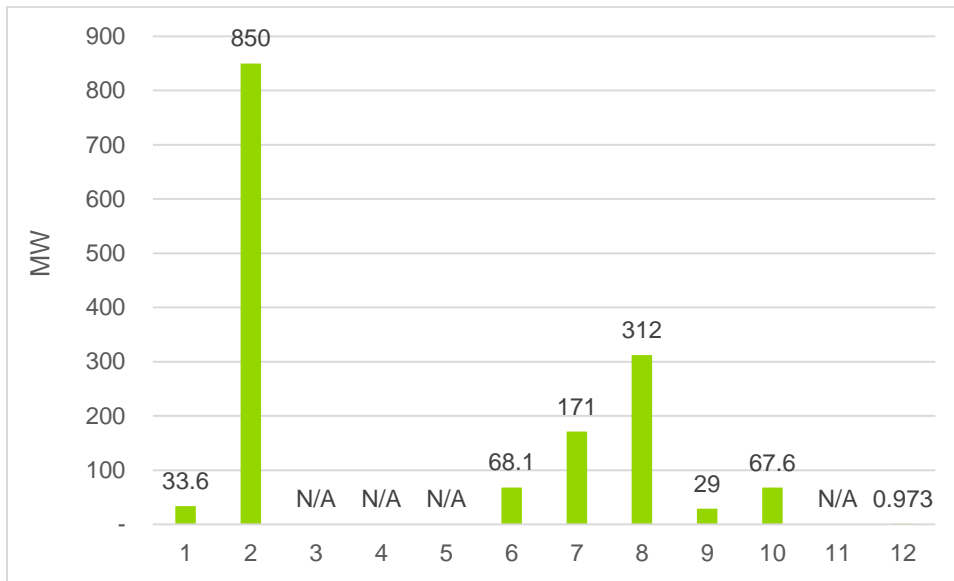
Source: Navigant

Figure A-4. Number of Applications to Connect, 2015³⁰



Source: Navigant

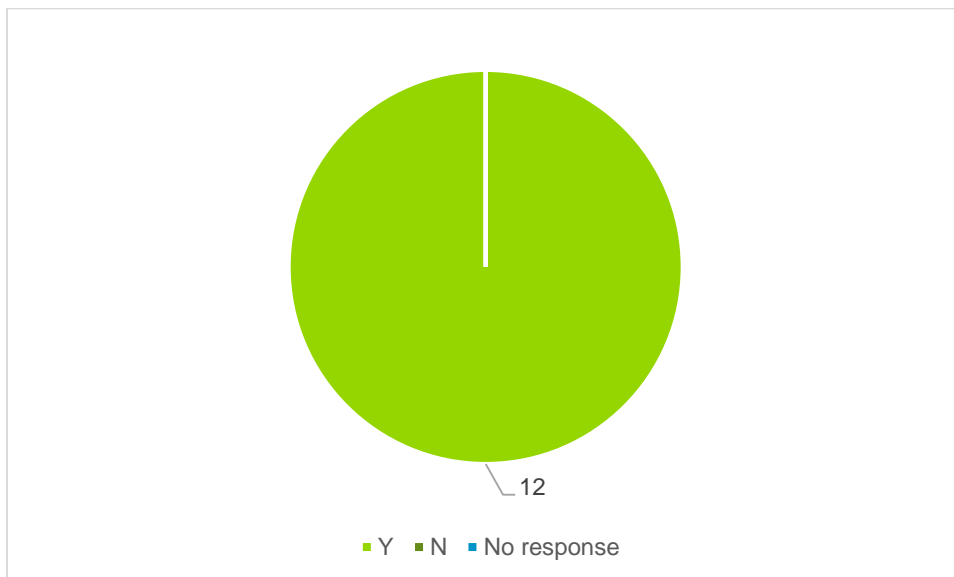
Figure A-5. MW of Capacity Associated with 2015 Applications by Utility³¹



Source: Navigant

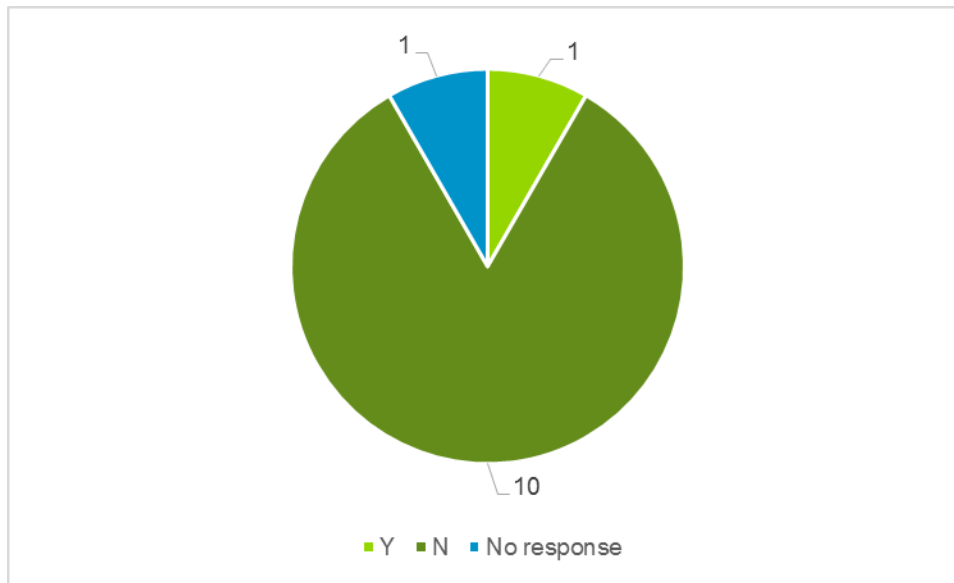
(2) DG Interconnection Process

Figure A-6. Web-Based Interconnection Platform (Y/N)



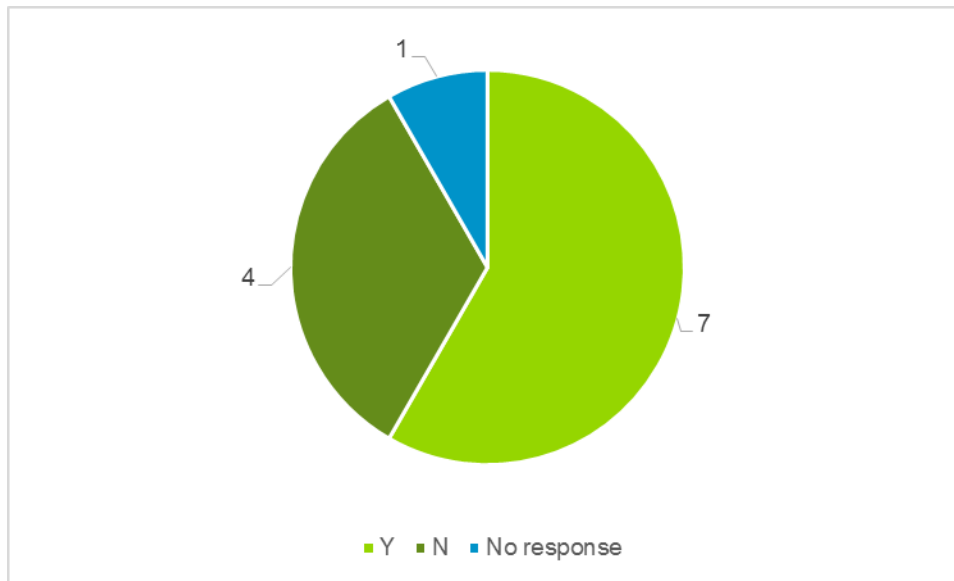
Source: Navigant

Figure A-7. Web-Based Maps to Indicate Capacity Availability (Y/N)



Source: Navigant

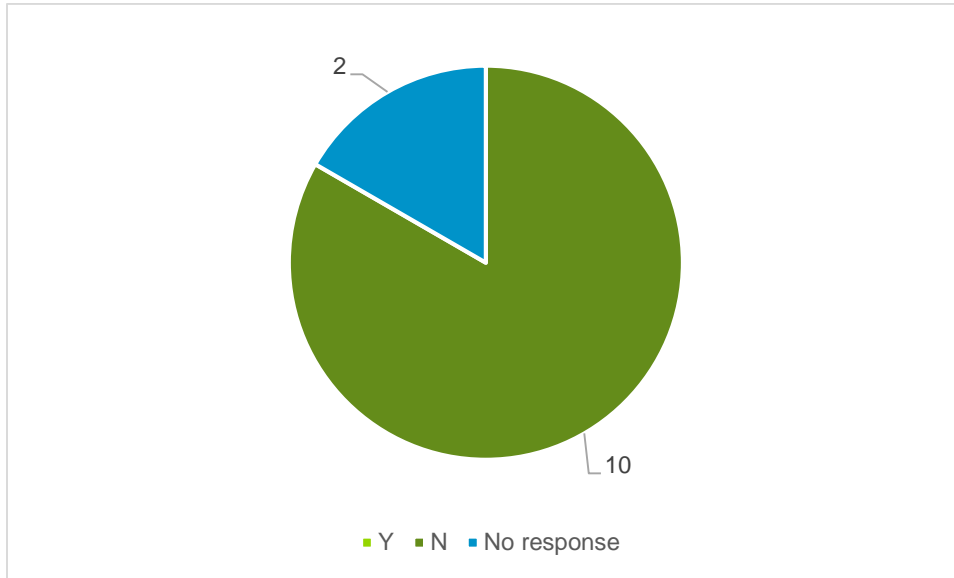
Figure A-8. Does Platform Manage Interconnection Process (Y/N)



Source: Navigant

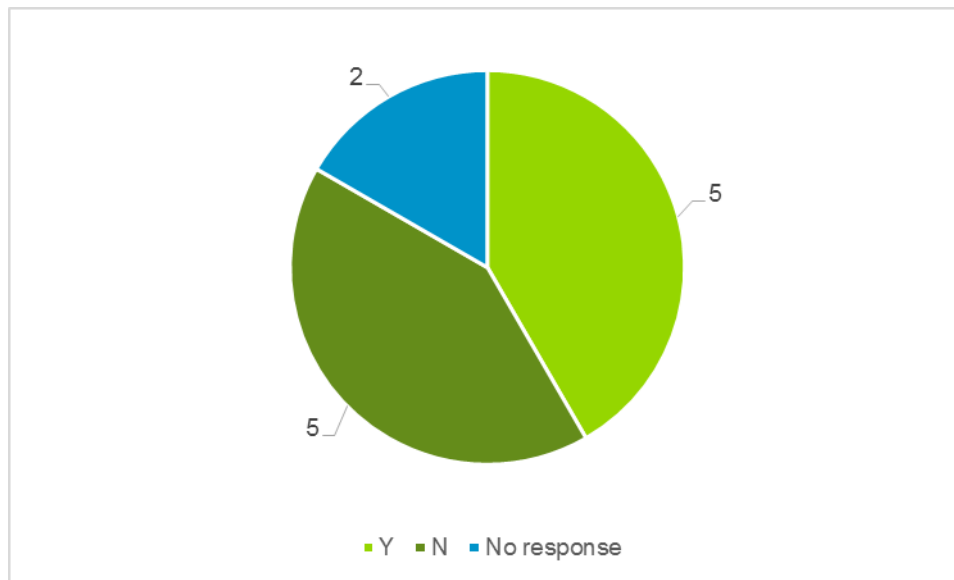
(3) Grid Protection: Technical Requirements for Interconnection

Figure A-9. Standardized Model for PV (Y/N)



Source: Navigant

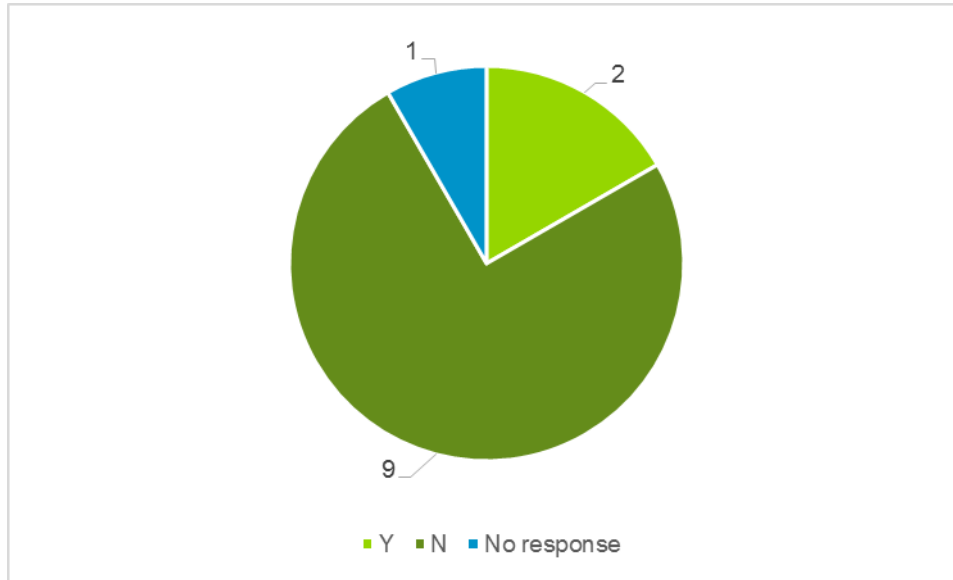
Figure A-10. DG Capacity Limit or Active Mitigation Due to Anti-Islanding Concerns (Y/N)



Source: Navigant

(4) Operational Safety

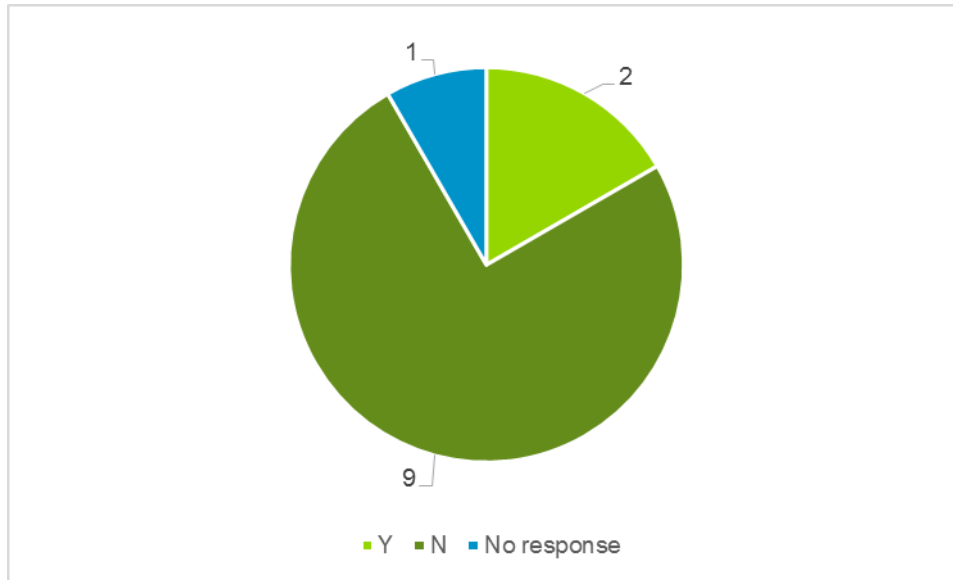
Figure A-11. DMS Used for Feeder Transfer (Y/N)



Source: Navigant

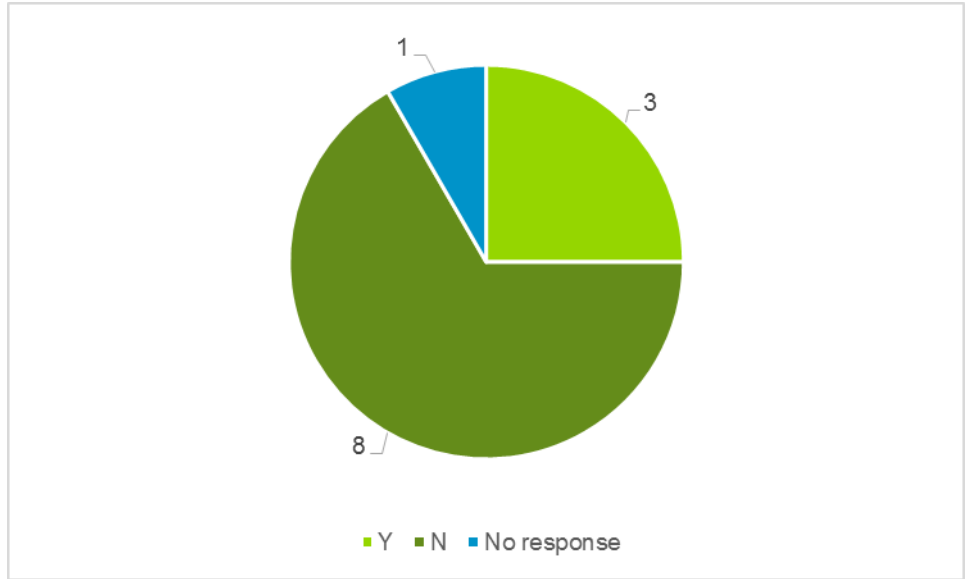
(5) Circuit/Grid Stability

Figure A-12. Hosting Capacity of Distribution Network Defined (Y/N)



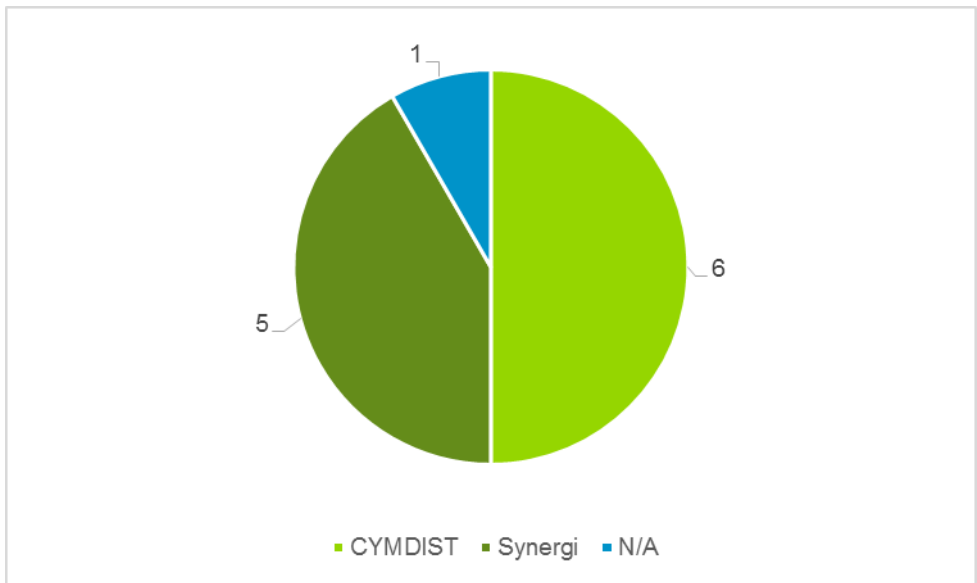
Source: Navigant

Figure A-13. Interconnection Process Addresses Transient Impacts (Y/N)



Source: Navigant

Figure A-14. Simulation Software for Distribution Studies



Source: Navigant