Transmission System Overvoltage Mitigation Through the Use of Distributed Generation (DG) Smart Inverters

by

Ali Said Alrayes

B.Sc., Electrical and Computer Engineering
Michigan State University, 2015

Submitted to the MIT Sloan School of Management and the Department of Electrical Engineering & Computer Science in Partial Fulfillment of the Requirements for the Degrees of

Master of Business Administration and

Master of Science in Electrical Engineering and Computer Science

in conjunction with the Leaders for Manufacturing Program
at the
Massachusetts Institute of Technology
May 2020

Signature of Author____

MIT Sloan School of Management
Department of Electrical Engineering and Computer Science
May 8, 2020

Certified by____

James L. Kirtley, Jr.
Professor of Electrical Engineering
Thesis Supervisor

Certified by____

Georgia Perakis
William F. Pounds Professor of Operations Research
Codirector, Operations Research Center
Thesis Supervisor

Accepted by____

Leslie A. Kolodziejski
Professor of Electrical Engineering and Computer Science
Chair, Department Committee on Graduate Students

Accepted by____

Maura Herson
Assistant Dean, MBA Program
MIT Sloan School of Management

This page intentionally left blank.

Transmission System Overvoltage Mitigation Through the Use of Distributed Generation (DG) Smart Inverters

by Ali Said Alrayes

Submitted to the MIT Sloan School of Management and the Department of Electrical Engineering and Computer Science on May 8th, 2020, in partial fulfillment of the requirements for the degrees of Master of Business Administration and Master of Science in Electrical Engineering and Computer Science in conjunction with Leaders for Global Operations Program

ABSTRACT

The objective of this project is to demonstrate the technical ability and cost-effectiveness of reducing electric transmission system overvoltage violations using distributed generation (DG) smart inverters connected to the electric distribution system. Overvoltage violations are situations when the system exhibits voltage levels outside of the acceptable range set by the American National Standards Institute (ANSI) of 105% of nominal system voltage.

The challenge that Atlantic Electric could potentially face from the rapid deployment of DG across its distribution system - driven by new additional renewable energy incentive programs in the US State in which it operates - is the underloading of its high voltage (69kV and 115kV) transmission lines causing overvoltage violations at the ends of the transmission lines. The traditional response to this challenge is to install system upgrades on the transmission system in the form of shunt reactors. However, these system upgrades are expensive and time-consuming to install, which could de-incentivize and delay the deployment of DG projects.

The solution we propose is to utilize the reactive power absorption capability of the DG inverters to absorb excessive reactive power from the transmission system.

In this work, we investigate feeders' maximum capability of reactive power absorption through distributed generation (DG) smart inverters by modeling two "representative" Atlantic Electric distribution feeders under different PV deployment scenarios based on the feeders' load and generation levels, among other factors. We then perform a cost-benefit analysis to compare against installing shunt reactors.

Our findings show that implementing an inverter-based solution has a range of significant cost-savings of up to $300,000/year when compared with installing shunt reactors on the transmission system. This arrangement, however, is one that hinges on the utility's ability to review regulatory and commercial with all stakeholders involved.

Thesis Supervisor: James L. Kirtley, Jr.
Title: Professor of Electrical Engineering

Thesis Supervisor: Georgia Perakis
Title: William F. Pounds Professor of Management Science, MIT Sloan School of Management; Codirector, Operations Research Center

This page intentionally left blank.

Acknowledgments

I would like to thank the MIT Leaders for Global Operations Program and especially professor Jim Kirtley and professor Georgia Perakis, my thesis advisors, for their support on this work.

Thank you to my fellow LGO and Sloan classmates for making my time at MIT an unforgettable and cherished experience. I couldn't have asked for better classmates.

Thank you to everyone at National Grid for the endless support in making this project a success. Thank you to Jacquelyn Bean and Samer Arafa for welcoming me into the team and encouraging me to ask the difficult questions.

Thank you to the EPRI Program P174 team for the technical support with this project.

Most of all, I would like to thank my wonderful family for the unconditional love and support they have given me over my eight years of living abroad and for their support during my two years at MIT.

This page intentionally left blank.

Table of Contents

List of Figures

List of Tables

This page intentionally left blank.

1. Introduction to Impact of Distributed Generation on the Electric Transmission System

1.1. Project Motivation and Scope

The electric power industry has recently been going through many changes in efforts to transition from the reliance on a fossil fuel-burning electric generation system to a cleaner and more sustainable one – often dubbed the Energy Transition [1]. Under the effort to combat climate change, the United States' federal and state governments have been introducing ambitious targets for the amount of renewable energy they would like to have as part of their jurisdictions' electricity generation mix. Additionally, the recent rapid decrease in costs to manufacture solar photovoltaic (PV) panels has made the transition even faster.

In 2016, the Massachusetts Department of Energy Resources introduced a new renewable energy incentive program under the Governor of Massachusetts' 2008 Green Communities Act (GCA) [2], which introduced tax credits for up to 1,600MW of solar-generated electricity projects. Titled Solar Massachusetts Renewable Target (SMART), the program is described as: "A long-term, sustainable solar incentive program to promote cost-effective solar development in the Commonwealth [3]." It is noteworthy that the SMART credit incentives are only provided to solar sites up to 5MW in size, making them of a size appropriate for interconnecting to the electric system at the low voltage distribution system (13.2kV or 13.8kV).

The SMART program was an instant success, and by 2019, Atlantic Electric was challenged with a backlog of DG interconnection requests. An interconnection request is submitted to the utility every time a DG developer plans a project [4]. These interconnection requests are screened internally at the utility and studied for their impact on the distribution system in a step called the "impact study." If any upgrades or changes are needed to the utility's infrastructure, the costs of those upgrades would be charged to the DG developer in the form of an interconnection fee. Once an interconnection agreement is in place between the utility and the developers, the project can be constructed and commissioned to start generating power and exporting it to the grid.

However, in 2019, and in response to the recent large number of DG interconnection requests, the Independent System Operator for New England (ISO-NE), which is the entity that assures the reliable operation of the high voltage transmission system, introduced new rules that would require the utilities in the ISO-NE area to study the impact caused by DG - connected to the distribution system and as small as 1MW in size - on the transmission system. In prior years, the transmission study cutoff limit was at 5MW, where anything smaller than that was deemed too insignificant to make an impact on the transmission system [5]. Given that most DG interconnection requests to Atlantic Electric were in between that range of 1MW and 5MW, a great number of projects would now have to be studied for their collective impact on the transmission system.

As these transmission studies were identifying potential problems from the new DG applications, we were motivated to find a solution. This project attempted to, at the heart of it, develop a resolution to reduce the time and cost to interconnect solar by mitigating any problems that might arise from the transmission studies. We then narrowed the focus of the work on specifically the overvoltage problem caused by underloading the transmission lines.

1.2. Problem Definition

Distributed Energy Resources (DERs) present a new challenge to electrical system planners as they disrupt the traditional way that the electrical system was designed to generate power at large generating stations (generation), step up the voltage and transport the power over long distances (transmission), and then step down the voltage and distribute locally (distribution).

DERs are a paradigm shift since they:

1. generate power at the distribution feeder level, as seen in figure 1
2. are too small and come in large quantities making them difficult to control centrally

Additionally, most DERs utilize inverter-based technologies that require a different operating approach than that of synchronous generators that the electrical system is so used to operating.

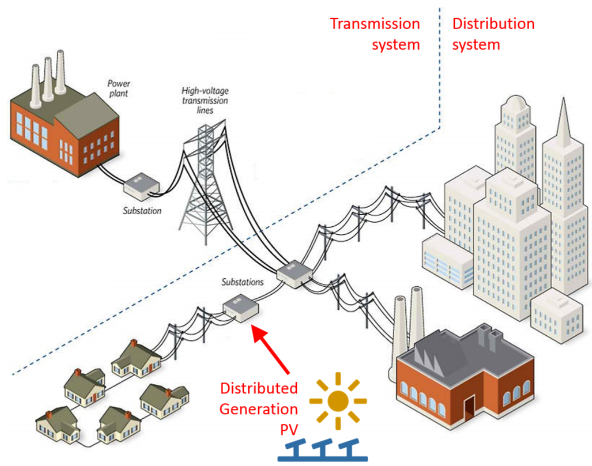

Figure 1: Electric power system schematic with DER

Challenges introduced by DERs are various, but most importantly to this project are those pertaining to saturating the ***capacity*** of the distribution feeders, raising distribution system ***voltage***, islanding and ***protection*** concerns, and finally, voltage concerns on the ***transmission*** system.

Capacity: In Massachusetts, most distribution feeders are operating at 13.2kV or 13.8kV. A distribution feeder starts at the substation transformer, where the voltage is stepped down from a transmission line (69kV or 115kV for Atlantic Electric in Massachusetts) and makes its way through a local area until it terminates at a point called the feeder-end. A typical distribution feeder can be up anywhere from 4 to 25 miles long, serve up to 20,000 electricity customers, and is set up in a radial form where it branches out from the main line. A typical

13.2kV feeder is usually made up of a 500kCMIL[1] type cable that has a nominal maximum current of 400A - often called thermal limit. Since voltage is fixed at 13.2kV and power is the product of current and voltage, it is a commonplace to use the amperage of a line to represent its power capacity which is calculated as:

$$P = V \times I \times \sqrt{3} = 13.2kV \ \times \ 400A \ \times \sqrt{3} = 9.14MW$$

Considering the amount of load a typical feeder is serving, Atlantic Electric estimates that the average maximum amount of DER production they can allow on a typical distribution feeder is around 12MW. It's noteworthy that this allocated maximum (12MW) is about 30% higher than the typical feeder thermal limit (9.14MW) since it's assumed the PV DER is only operating at its maximum rated output for very short durations (middle of a bright and sunny day) at which point, the utility can utilize other measures to make sure the distribution feeders aren't overloaded. Additionally, since the DER sites are often dispersed along a feeder, Atlantic Electric can plan and identify specific areas along the feeder and install a larger cable if the thermal limit is being exceeded.

Given that a typical large-scale solar DG site is within 1MW and 5MW, a feeder can realistically only handle connecting 3 to 12 DG sites solely based on capacity. At Atlantic Electric, when a DG application is presented to interconnect to a saturated feeder, a study is made to analyze any upgrades that may be needed on the feeder or the substation transformer to allow the new DG site to interconnect. These upgrades can be so large in scale to the point that a new feeder or new substation could be designed to allow the DG to interconnect. All the costs associated with any needed upgrades are covered by the DG developer in the form of a higher interconnection fee. The amount of available capacity on a distribution feeder until it requires upgrades is called the Hosting Capacity [6].

Voltage: Increased power generation on a distribution feeder can cause voltages to rise. Distribution feeders were not designed to handle voltage-rise; in fact, most feeders were intentionally designed with additional capacitor banks to increase the voltage across the feeder due to nature of decreasing voltage along the length of a distribution feeder – an effect called voltage-drop [8]. This is a problem that arises since distribution feeders are almost always strictly radial in their design – meaning that feeders are connected in a star-shaped fashion with the substation as the common node – where DER are increasing the line voltage in an unexpected manner as seen from the capacitor banks that are meant to combat voltage-drop. For more research on a PV plant's impact on feeder voltage, see [7].

While a logical suggestion is to remove capacitor banks from the distribution feeders now that we have DERs, that is not possible since the power generation of DERs is highly variable and uncontrollable. Hence, a new distribution-level voltage control approach is needed, one that targets both voltage-rise and voltage dip by inductance and capacitance respectably. This

---

[1] KCMIL – Unit for measuring electrical cable size from the American Wire Gauge (AWG) representing cable area in thousands of circular mils. A circular mil is the area of a wire one mil in diameter.

holistic voltage control approach (in both quadrants of the reactive power spectrum) is possible using fast-switching power electronics.

Protection: By protection, we are referring to the ability to interrupt a power source when needed by the system operators or due to autonomously-controlled devices that respond to faults on the system. In the world before DERs, where power was flowing in one direction downstream from generation to transmission to distribution to the final load, protection was designed to interrupt power flow accordingly. However, now that we have installed power generation in what was traditionally called the downstream end, these protection schemes need to be revised.

Chief of those protection concerns is the scenario of having a section of the grid be disconnected from the rest of the system but still be powered by a local DER connected to that section. This scenario, called islanding, would present a hazard to the systems and operators of the grid who are assuming that power was cut off due to the system fault, but on the contrary, it is now being supplied locally from the DER. Anti-islanding schemes such as Direct Trip Signals are installed to disconnect a DER site at the point of interconnection POI. For details on DTT, [9].

Transmission: As more DG is connected to the distribution grid, less of the system load is required to be supplied by the transmission system – and consequently, the large-scale generators. While this may sound great since it reduces the need to rely on larger generating stations connected to the transmission system, usually requiring fossil fuels to generate electricity, it has a negative consequence of lightly-loading the transmission lines beyond the limits they were designed for.

When a transmission line is lightly loaded is exhibits capacitive behaviors and introduces reactive power to the system, which in turn raises the voltage at the line ends, an effect described as the Ferranti Effect [10]. The Ferranti Effect is seen on long sections of transmission lines in areas with few large-scale generation - that can provide voltage support - and small amounts of load.

Out of the ***capacity***, distribution ***voltage***, ***protection***, and ***transmission*** challenges described above, the focus of this work is solely on the transmission overvoltage challenge.

1.2.1. Sunny Spring Day Case Study

To highlight how the solar PV contributes to the issue of underloaded transmission lines, we studied the New England electric system to learn if the problem was a future issue, or one that exists today. For this, we looked at 5-minute net load data[2] across the ISO-NE[3] system for an entire day where there was high solar irradiance – a sunny day - and compared it against the same data from a different day with low solar irradiance – a cloudy day [11]. The hypothesis is

[2] A data-series representing the electrical load on the bulk transmission system sequenced every 5 minutes

[3] Independent System Operator for New England – Entity responsible for operation of bulk transmission grid

that the combination of large DG solar PV and low system demand on a sunny spring day will produce reduced loading on the transmission system.

The two case study days chosen were the Friday, May 10th, and Saturday, May 11th of 2019. Where the 10th was reported to be cloudy in Boston, the 11th was sunny [12].

This difference in irradiance resulted in a stark difference in the amount of power generated by solar PV sites in New England over those two days. Figure 2 shows one of those sites – an Atlantic Electric-owned 1,000kW rated PV facility in central Massachusetts - which saw a peak production of only 200kW (20% of rating) on Friday the 10th as the PV arrays sat under the clouds for most of the day, while a peak production of 900kW (90% of rating) on Saturday the 11th. Data collected for figure 2 is courtesy of Atlantic Electric.

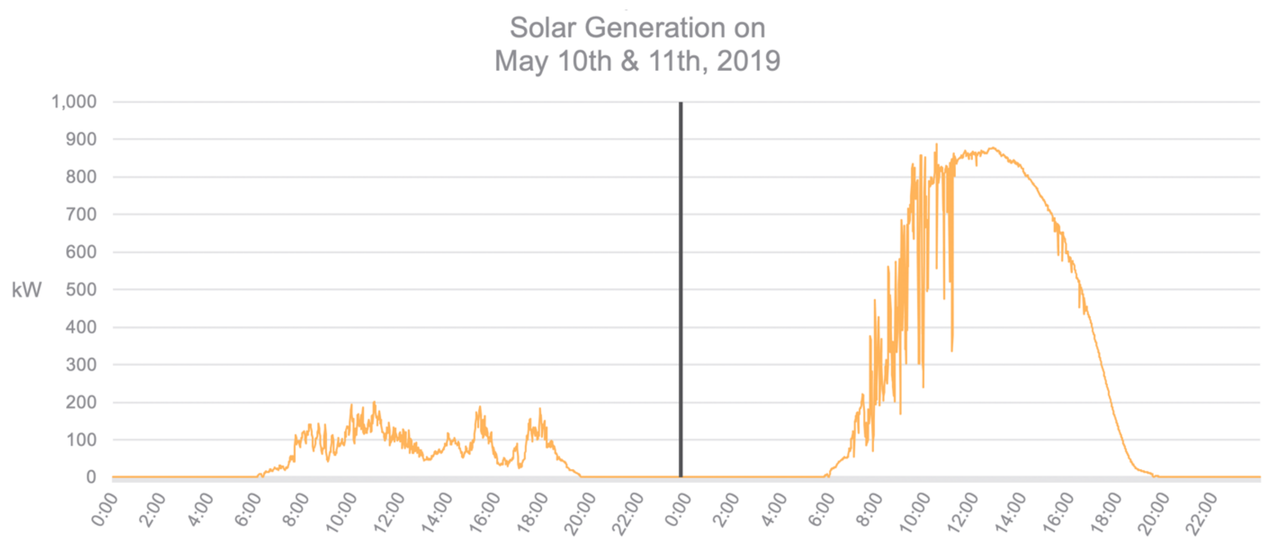

Figure 2: Solar generation from sample Atlantic Electric PV plant on May 10th and 11th

When aggregating the effects of all the individual solar PV sites in New England, we see that the transmission system demand, as shown in figure 3, has a dramatically different shape. We see on the 11th a significant dip on the transmission system demand (about 3,000MW). This is a result often called the "duck curve," where the midday transmission system demand is being supplied by local solar PV outside of the bulk transmission system, and hence the demand curve is altered [13]. It's worth pointing out too that the peak system demand (~13,500MW) on the 10th is higher than that (~12,00MW) of the 11th because of the difference in power consumption from a weekday to the weekend; however, this does not affect the results observed from the "duck curve" effect.

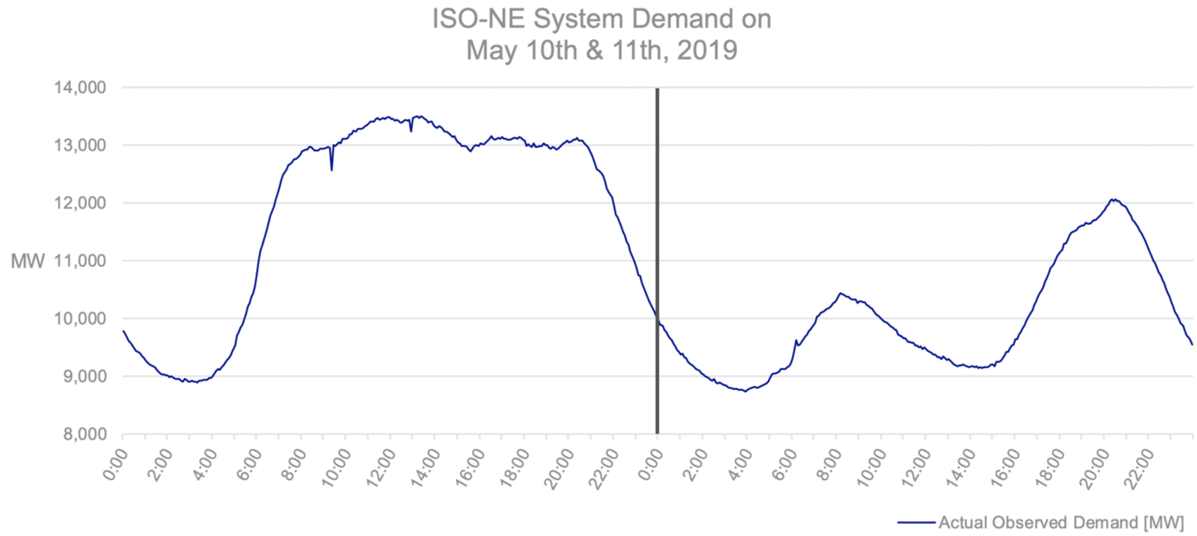

Figure 3: ISO-NE system demand on May 10th and 11th, 2019

However, the issue with the May 11th "duck curve" as it relates to the Ferranti effect is not yet clear since the increase in solar PV generation doesn't really make the minimum load (around 14:00) seen on the system lower than what the system already experiences during the nighttime (around 4:00). This, however, is rapidly changing, where if one were to account for the roughly 743MW of PV forecasted to be connected on the Atlantic Electric system alone by 2023, and assume a similar demand curve, then we should expect to see a system where the daytime minimum load is lower than the nighttime minimum load, as seen in figure 4. As more solar PV comes on to the system, the daily minimum load can be expected to decrease, meaning lighter and lighter demand on the transmission lines – and that is the core of the problem we are trying to solve.

An example of the accelerated pace of change is seen on February 26th and 27th of 2020, where ISO-NE reported its first back-to-back days with daytime min loads [14].

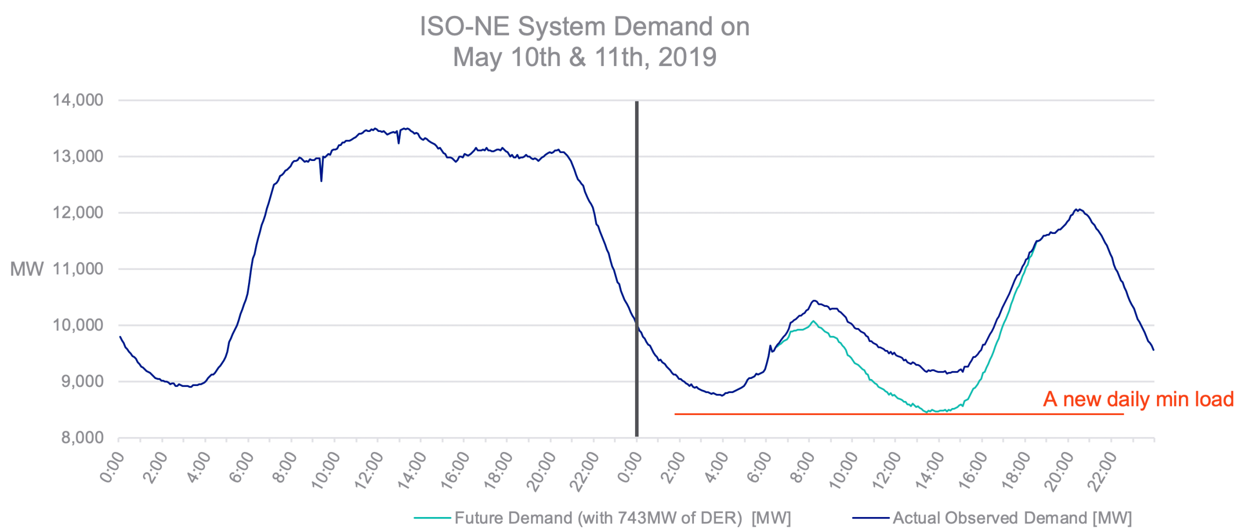

Figure 4: ISO-NE system demand on May 10th and 11th with additional 743MW of forecasted PV modeled

Finally, it is important to note that while this exercise shows the impact on the entire ISO-NE transmission system demand, the problem is more exaugurated if studied more granularly by taking a closer look at specific transmission lines or nodes within the system that have larger amounts of DER in their region.

To summarize, the problem we are trying to solve is the overvoltage seen on transmission lines, which is caused by these transmission lines' underloading, which in turn is caused by the increased DER penetration on the distribution system.

Note: The future demand curve in Figure 4 was generated by assuming a 743MW reduction in demand at the time of daily min for the observed data and then linearly decreases following a typical solar generation bell curve shape until it reaches 0 at solar sunrise and sunsets for May 11th, 2019. This is just a representation for illustrative purposes that is accurate at the max/min values, but it doesn't accurately predict the shape of the future demand curve at every moment in time.

1.3. Smart Inverters

Inverters, a critical component of a solar PV system, are devices that convert the DC power generated by photovoltaic panels to AC power that can be interconnected to the grid.

Smart inverters, or sometimes called advanced inverters, are a new class of inverters that can provide additional functions to their core DC to AC power conversion. These functions rely on their ability to use their power electronics to shift the phase angle of their current to generate or absorb reactive power and hence operate in all four quadrants of the power spectrum [15].

"Reactive power represents power that is seemingly just 'sloshing around' [in a system], or being exchanged between source and sink at twice the electrical frequency … Reactive power is measured in volt-amperes reactive (VARs) … and plays a very important role in controlling voltage in electric power systems [16]."

There is no precise definition that qualifies an inverter to be called a Smart inverter; however, the power industry has recently taken the IEEE-1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces – as the standard for what qualifies as a grid-connected inverter with advanced functions. IEEE-1547 went through multiple evolutions since its initial publishing in 2003. The 2018 version is the first that requires inverters to support reactive power voltage regulation [17], [18].

Another qualifier for what accounts as a smart inverter is those that adhere to the California Public Utilities Commission (CPUC) 2014 revision of the Rule 21 tariff where they incorporated smart inverter requirements as advised by the Smart Inverter Working Group in its January 2014 report "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources [19], [20], [21]." Similar to California's Rule 21, Hawaii's Rule 14H effective 2018 incorporated Grid Support Utility Interactive (GSUI) Inverter functions [22]. Finally, UL 1741 is the industry standard for manufacturers to build their devices [23].

Finally, ISO-NE and Atlantic Electric have their own set of requirements for smart inverters.

It is important to note that as of the end of 2019, no testing standard for assuring smart inverters are up to specifications has been published. A testing standard is the important next step to approve the installation of these devices, knowing what they have been approved for. Despite that, most inverter manufacturers on the market today build their inverters to be capable of the for mentioned IEE-1547, Rule 21, Rule 14H, and UL 1741 standards.

1.3.1. Smart Inverter Functions

The ability to regulate voltage using power electronics is not new; however, the reliance on spare capacity in solar PV inverters to achieve it is a new application that has only been developing in the last five years. Today, it is commonplace for inverters to have a variety of "advanced functions [24], [25], [26], [27], [28]." A list these of advanced functions:

- Volt-VAR: Defined by a Volt-Var curve, the inverter will continuously adjust the reactive power absorption or generation depending on a functional relationship with the terminal voltage. Volt-VAR functions are usually linear in the low and high voltage ranges using a fixed absorption/generation unit per unit of voltage change with a so-called dead band region where voltages are acceptable (+/- 5% of nominal) where no absorption or generation of reactive power happens.

- Volt-Watt (curtailment): Defined by a Volt-Watt curve, the inverter will adjust its real power output based on a functional relationship with the terminal voltage. Volt-Watt functions are usually linear, where the real power output will cautiously be decreased as the voltage increases. In low-voltage situations, a Volt-Watt function can't help beyond deploying its maximum rated amount of real power. For details on Volt-Watt, see [29].

- Hz-Watt (curtailment): Another form of real power curtailment, the Hz-Watt function, will react to the system frequency on the inverter terminals and adjust the real power output accordingly. This function is seen as easy to implement since the frequency is identical on different points on a distribution feeder where any DG site could be connected, as opposed to voltage-input functions where the voltage is known to be different at different points on a feeder. For details on Hz-Watt, see [30]

- Frequency ride-through (transient stability capability): This function dictates that the inverter be able to maintain power generation during low or high voltage and frequency conditions. Doing so will ensure that the inverters don't consciously trip and cease to provide power in abnormal events. Ride-through curves describe the minimum elapsed time that an inverter is allowed to trip given a certain frequency or voltage level.

- Momentary cessation: This function requires the inverter to stop power generation within a certain amount of time in the event of an electrical fault. The inverter is to detect abnormal current levels and momentarily stop generating power to the interconnection until the fault is cleared, at which point power generation can resume.

- Fixed power factor: This function requires the inverter to maintain a pre-set constant power factor (pf) ratio. The pf ratio represents the ratio of real and reactive power going through the inverter. When the pf is set to <1.0, the inverter is said to be consciously absorbing reactive power and hence reducing system voltage and vice versa.

- VAR priority (curtailment): In this function, the inverter shall maintain a certain amount of reactive power generation or absorption at the expense of any real power that might be generated. The inverter will give the priority for a pre-set amount of reactive power and curtail any real power that exceeds the remaining apparent power capacity to adhere to the limitations of the inverter's apparent power rating (VA. For details on VAR priority, see [31].

  To illustrate this, let's assume a sample inverter's rating is 1,000kVA [$S = 1000$] and is set to VAR priority mode at 600kVAR [$Q = 600$]. The inverter will then curtail any real power output coming from the inverter that exceeds the real power capacity given VAR priority [$R \quad = \sqrt{S^2 - Q^2} = \sqrt{1000^2 - 600^2} = 800kW$]. In theory, for our sample inverter, this setting allows the inverter a VAR capacity of 60% of its rating, while only curtail 20% of its rated real power.

  This function is used when a predetermined amount of reactive power is known to be needed regardless of system voltage, frequency, or real power – as is the case for the work in this project.

1.4. Thesis Organization and Contribution

This thesis is organized into three main parts. First, in Chapter 2, we present a smart inverter-based solution to the problem described above. We go into detail about the architecture and implementation of the proposed system. We then, in Chapter 3, discuss the modeling made using representative Atlantic Electric distribution feeders to verify the viability of the solution and present detailed results on the effects of the purposed solution on the distribution system. Using those results, in Chapter 4, we explore through a cost-benefit analysis the value proposition of the solution and quantify the annual savings estimated from implementing it. To conclude, we present our findings on this project and propose further work that can be done to build upon this analysis.

The contribution of this work is threefold:

- The design and specification of an implementable system that can reduce overvoltage on the transmission system through DG inverters on the distribution system
- The definition of maximum reactive power absorption limits of two of Atlantic Electric's distribution feeders – what we call "Reactive Power Hosting Capacity."
- The definition of the attainable cost savings from implementing the inverter solution

This page intentionally left blank.

2. Inverter-Based Solution System Description

2.1. Overview

Atlantic Electric, as a regulated utility in the Massachusetts, does not own or operate any of the electricity generation assets connected to its system - with the exception of less than 20 solar PV sites that the utility owns and operates; data from one of these sites was presented in figure 2. Rather, third-party owners-operators, herby titled Solar Developers, connect their equipment to the utility. This comprises all equipment required to operate the solar PV plant, including the inverters that transform power from DC current generated in the PV plants to AC current to connect onto the utility grid. However, it is Atlantic Electric's responsibility to maintain the appropriate power quality on the system. Currently, this is handled through the Standard Interconnection Agreement (ISA), which spells out the technical and operational requirements that the project must meet before it can be interconnected. However, the additional smart inverter functions are not currently a part of this interconnection agreement. On top of having to revise the ISA, the utility's challenge becomes relying on equipment it doesn't own or operate to regulate its own system.

A potential solution to this question is in DERMS – Distributed Energy Resource Management System. DERMS allows the utility to access and operate all DER connected to its system in the same manner it has in control over its network architecture. However, DERMS systems are yet to be deployed at scale and at a cost-beneficial offering to quote as a reliable solution. For more details on DERMS systems, see [32], [33].

As such, it was the goal of this project to design a simple, affordable, and readily-available control system that Atlantic Electric can implement on its system today.

2.2. DG Control Architecture

There are two operating schemes proposed in this project: 1. Local control (automatic) and 2. ISO control (manual). Central to these control approaches is the use of the Schweitzer Engineering Laboratories SEL-3555 device [34] that acts as a real-time automation controller (RTAC) at each substation. The hardware specified works to support both control architectures in a combined packaged solution herein referred to as "the control system."

These two operating schemes were designed based on the following criteria:

- Minimal transmission-distribution control interference
- No impact on the operational flexibility of the distribution system
- Minimal cost associated with new equipment procurement and installation

1. Local control (automatic mode), as seen in figure 5:
   In this approach, the RTAC's are to actively monitor the transmission-level (high) voltage at the substation interconnection point. This is achieved through a set of 3-phase potential transformers connected to the high side of the transmission-distribution substation transformer.

The RTAC then compares the real-time system voltage against a pre-set voltage threshold of 1.04pu, and if higher, then automatically sends commands to all the participating DG inverters in all the distribution defers connected to its substation. This command is a binary on/off signal that instructs the DG inverters to enter/exit fixed-VAR mode.

Fixed-VAR mode in the inverters is a VAR priority setting where the inverters will utilize the excess apparent power capacity of an inverter to absorb a certain amount of reactive power, and if that excess is not enough, then it will prioritize the absorption of VAR at the expense of outputting real power. In this mode, the inverters will have a pre-determined VAR absorption target that is based on the system engineer's study of the amount of reactive power needed from that entire substation to act as a "virtual shunt reactor" for the transmission system.

Once all these inverters start absorbing reactive power, the aggregated effect will create a leveling of the voltage at the substation to the acceptable range and avoid a violation of exceeding ANSI limits.

However, the description thus far is a simplified portrayal of the control system. Practically, in order to implement in the real world, one has to also account for the potential for instabilities, and hence, a more staggered approach would have to be developed. For example, for each 0.1pu voltage increase, a certain amount of DER inverters is set to absorb reactive power. The nature of this relationship can be further defined per the specific conditions of the system under study.

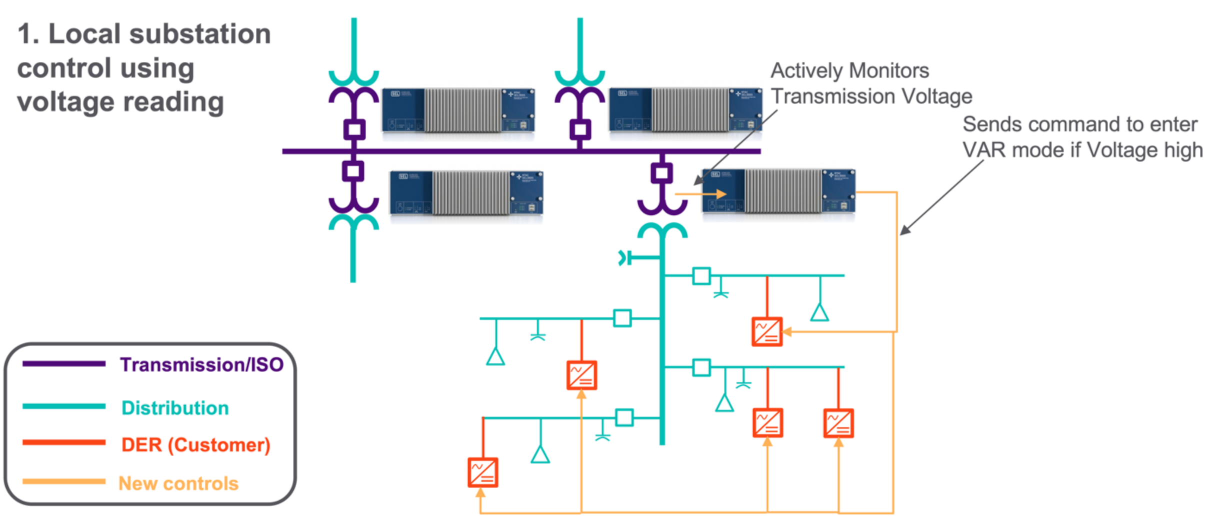

Figure 5: Local control (automatic mode) architecture

Local Control provides the advantage of no real-time transmission-distribution control interfaces. This is important because it allows the operators of the distribution system to continue to flexibly manage their system without reliance on the transmission operators for anything. However, the disadvantage is that the voltage reading is local to the point of interconnection, which is not ideal since points on the transmission system that see voltage-rise don't necessarily coincide with where the "virtual shunt reactor" might be needed. It is for this reason that the second control architecture was developed.

2. ISO Control (manual mode), as seen in figure 6:
   ISO control is a secondary control architecture that relies on the same equipment as Local Control but introduces the benefit of monitoring across the entirety of a transmission line or across a section within the transmission system operator's entire service area.

   This is done by introducing a communications link between the transmission system operator (TSO), or in the case of Atlantic Electric in Massachusetts, the Independent System Operator (ISO). The ISO has the ability to observe real-time electrical system demand across the system and anticipate minimal load durations. It is in those durations that the ISO can demand certain substations to act as "virtual shunt reactors" and start absorbing reactive power. This is identical to how the TSO/ISO would operate shunt reactors installed on the transmission side.

   After the substation RTAC's receive the load-controlled directions from the TSO/ISO, they follow the same operations as detailed in the Local Control section by communicating a binary signal to the DG inverters to enter into fixed-VAR mode, which the inverters do based on a pre-determined VAR absorption target.

   The TSO/ISO can communicate to the RTACs any desired amount of VAR absorption out of a set of discrete predetermined settings to simulate a variety of sizes of the "virtual shunt reactor." Based on that value, the RTACs would then decide which inverters on the substation to toggle the binary VAR priority setting on to achieve the desired VAR absorption target.

The aforementioned Local and ISO control methods were specifically designed for this project based on Atlantic Electric's prior experience with the devices specified and the requirement to simplify the control as much as possible – including costs. This yielded a system with a narrow scope (absorbing VARs based on measurement) focused on a specific part of the system (substation). Alternatively, if the requirements were less restrictive, a much more expansive Distributed Energy Resource Management System (DERMS) could have been specified. DERMS are off-the-shelf commercial systems that promise to integrate the management of DER to achieve a variety of grid-needed controls. However, DERMS systems come at a high cost, and with other complex issues, that wouldn't be ideal for the specific problem scope this project was interested in.

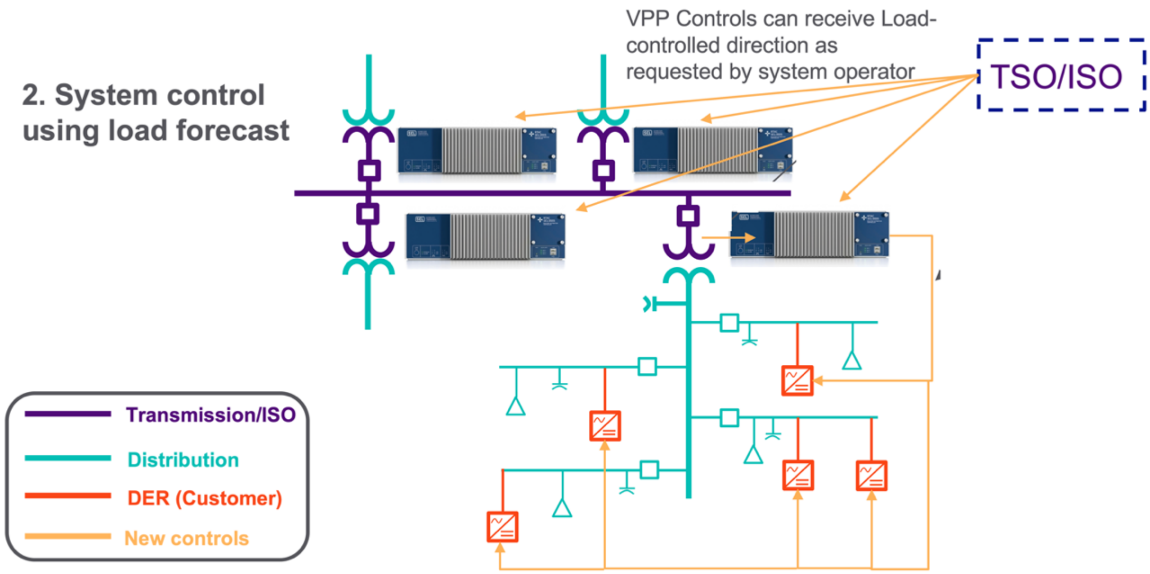

Figure 6: ISO control scheme (manual mode) architecture

2.2.1. Bill of Materials

The additional equipment and materials required for implementing the control system are specified in table 1. There are shown in yellow and labeled "New Controls" in figures 5 and 6.

Item	Quantity	Additional Needs/Remarks
SEL-3555 RTAC	1 per substation	Rack space, DC power, and auxiliary equipment required for SEL-3555 installation
3x single phase Potential Transformers	1 per substation	Pole, mounting hardware, power cabling, control cabling, and grounding equipment.
Fiber connection for local area network between RTAC's and DG inverters	1 per participating inverter	Space on distribution system poles
Cellular communication connection between TOS/ISO and substation	1 per substation	

Table 1: Bill of materials of the control system

2.3. Implementation across the Transmission System

Transmission voltage-rise issues are not isolated problems. When a system experiences power quality issues in one place, it is usually felt by the system in other areas too. It is for this reason that we recommend taking a holistic approach when analyzing the settings of the parameters for this problem. These parameters include:

- i - Target substations where reactive power absorption is needed
- X_i - Target amount of reactive power absorption needed per substation
- $MaxV_i$ - Voltage value at which reactive power mode would automatically turn on

- $NormV_i$ – Voltage value at which reactive power mode would return to being off after being turned on

Other local factors to the distribution system that are important to note here:

- j – Target feeders within a substation where reactive power absorption is allowed
- k – Target participating DG inverter within a feeder where reactive power absorption is allowed

For this work, no analysis was performed to aggregate the results of the individual substation's reactive power absorption effect on the whole of the transmission system. However, to most accurately define the parameters above, a system-wide electrical load flow analysis study would need to be conducted.

2.4. Advantages and Disadvantages of Solution

The following discussion of the advantages and disadvantages of the inverter-based solution is in comparison with the alternative solutions that an electric utility might implement to resolve overvoltage on the transmission system. The alternatives solutions include:

1. Installing Shunt reactors on the transmission system
2. Redesigning the distribution feeder voltage regulation control system by removing or adding capacitor banks, reactors, dynamic VAR compensators.
3. Refusing to connect the DER

Advantages of inverter-based solution:
Cost Reduction: The basis of this solution is the reliance on DER inverters to perform voltage regulation. This eliminates the need to design and install any form of reactive power sinks such as shunt reactors or VAR compensators. Additionally, the control architecture described in 2.2 relies on very low cost and accessible equipment that utilities are already used to installing.

Reduce customer's interconnection cost, which improves the utility-customer relationship: Due to the cost reductions mentioned above, significant savings will make a positive impact on the relationship between the utility and the DER customers.

Simple yet flexible controls: Without the need for complex DERMS, the control architecture specified in Section 2.2 is designed specifically for the problem at hand and hence simplifying the operational controls.

Disadvantages of inverter-based solution:
Requires reliance on equipment not owned by utility: Utilities would have to rely on customer-owned DER to regulate their own system voltage. This would require regulatory and commercial review to ensure system reliability is maintained at all times.

Adds complexity to distribution voltage control: From the perspective of the distribution system operator, this added functionality to support the transmission system would introduce new levels of complexity. This might hinder operational flexibility and require developing alternatives to existing procedures. For example, if one feeder is providing transmission overvoltage support through its DERs suddenly sees an unexpected electrical fault, the operators would have to not just convert the load to an alternative power source, but also find ways to support the transmission voltage.

With complexity comes an added risk of part failure: With more equipment and complexity added to the feeders, comes the risk of weak links and points of failure.

3. Modeling Representative Distribution Feeders with Smart Inverters[4]

In order to prove the technical feasibility of the purposed solution, we selected two representative distribution feeder models and performed a series of power flow analyses to explore the limitations of the solution in the real world.

In the next few sections, we will discuss the process of modeling the distributions feeders, the selection of the two feeders under study, a conversation on the parameters chosen for the study, and finally, the results from the analysis and how they can be expanded upon.

3.1. Modeling Methodology

The process followed to model the capability of the distribution feeders is seen in figure 7. This process was automated using a Python script that was developed to accept any of Atlantic Electric distribution feeders and then run the electrical load flow analysis simulations on the CYME[5] modeling software.

For each distribution feeder model:

- A VAR target range was defined. In most cases this was 0-24 MVAR
- A selection was made on the subset of DER allowed to participate in the modeling
    - Feeder vs. substation
        - Feeder – meant only the PV connected to the study feeder was made to participate
        - Substation – meant that all PV connected to any feeder connecting up to the substation where the study feeder originated was considered.
    - Pending DER or All DER
        - Pending DER – referred to DER sites in the Atlantic Electric interconnection queue that applied to interconnect by December of 2018, but had still not gotten approval to connect.
        - All DER – referred to both pending and existing (connected) DER
- We then compared each study feeder (or substation) for their reactive power capability against the defined VAR request. The inverters were assumed to be in fixed-VAR mode and that the requested VARs per inverter would never be more than the reactive power equivalent of 0.8 power factor. A 0.8 power factor was chosen as an extremely low estimate for this. If not enough reactive power was available on the feeder (or substation), additional reactive power was assumed to be added through the installation of other reactive power sources. Reactive power sources, regardless of their type or cost, were quickly ruled out in our analysis since from Atlantic Electric's perspective, it was more optimal to rely on parallel feeders' DER (Substation mode) than it was to install any new equipment.

---

[4] Work in this chapter was made in collaboration with the Electric Power Research Institute (EPRI) Program P174 - Enabling Integration of Distributed Renewables

[5] The CYME Power Engineering software is a suite of applications composed of a network editor, analysis modules and user-customizable model libraries from which you can choose to get the most powerful solution developed by the CYME Power Engineering Software Company – now part of Eaton Corporation.

- Next, we ran a CYME load flow analysis on the distribution feeder for a variety of scenarios of generation and load conditions on the system and observed the voltage and thermal impacts of the new system on the distribution system. We varied generation (any and all DER even if not participating in VAR absorption) from a 0-100% scale while varying the load on each feeder over a 25-100% scale.
- When analyzing at the load flow results, if any feeder violations were observed, a distribution feeder mitigation effort was applied, and the study was re-run until no violations were seen.
    - Feeder violations occur when:
        - component overvoltage: voltage on any part of the system exceeds 5% of its nominal voltage
        - component Under-voltage: voltage on any part of the system falls below 5% of its nominal voltage
        - component overloads: apparent power on any part of the system exceeds its rated levels
    - Mitigation factors include:
        - Reconductoring sections of the cable: installing new cable with larger power rating
        - Installing new voltage regulators.
        - Replacing substation transformer: installing a larger (usually 55MVA) transformer in place of the existing one (usually 40MVA).

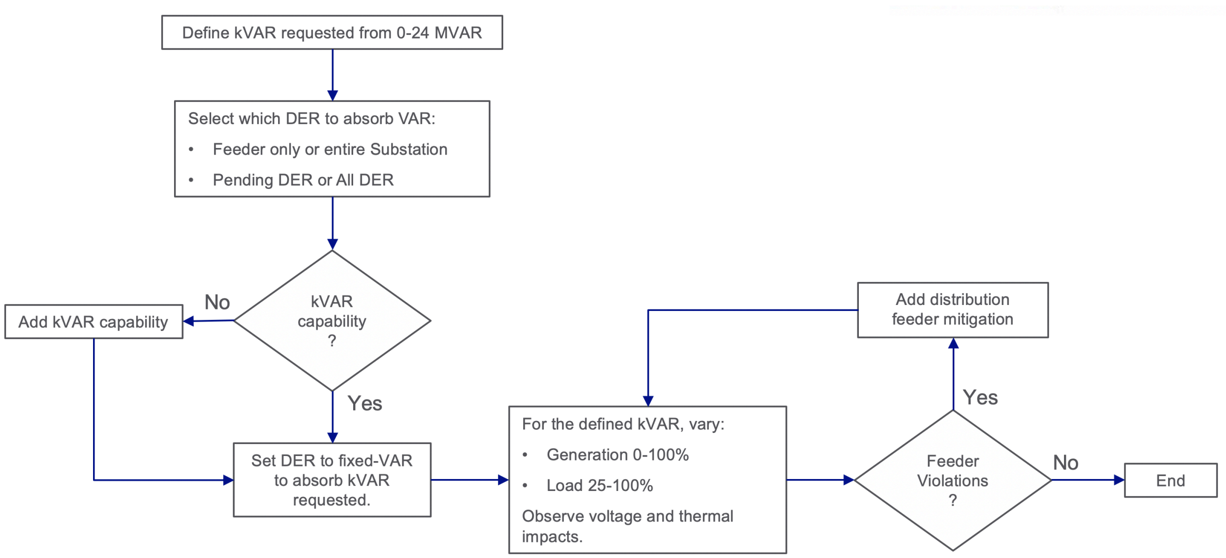

Figure 7: Feeder modeling methodology flow diagram

The distribution feeder models were built and analyzed in CYME Power Engineering Software. A software script was written using Python that executes the series of load flow analyses on the desired distribution feeder under study to automate the tedious analysis process for every scenario. This process should facilitate the ease of studying additional feeder when the utility wishes to.

3.2. Representative Feeders Descriptions

Atlantic Electric has hundreds of substations and feeders in its US service territories. Two distribution feeders were selected to be studied for this project based on the following factors:

1. Be in the ISO-NE Western/Central Massachusetts Wholesale Load Zone Area[35], as seen in the grey area in Figure 8. This represented the area with the highest urgency, as presented by Atlantic Electric. In this area, DG interconnection requests were put on hold until their impact on the transmission system could be studied. As such, it was paramount to find a solution utilizing feeders in this area.
2. Be one of the special feeders with an Atlantic Electric-owned DG site. Atlantic Electric, through a special exemption, owns and operates 31 DG sites across Massachusetts. 18 of these sites have smart inverters installed. We wanted to prioritize studying these feeders as Atlantic Electric had full control where real-time changes could be made to their advanced function settings without the need to go through a third-party solar developer and modify the utility's standard interconnection terms.

Seven feeders were found to overlap the two requirements mentioned above, as seen in the orange markers in Figure 8. The next step was defining criteria for which of these feeders were to be studied first. Only two of the seven feeders were selected due to time and budget constraints. The choice of the two feeders was based on the following criteria:

- Diversity in impact factor. The impact factor is a term derived by EPRI and is a variation of a hosting capacity calculation that represents the quantity of impact an addition of a DG site would have on the feeder.
- Diversity in transmission line connection. Atlantic Electric's transmission system is a mesh of 115kV lines (blue in figure 8) and 69kV lines (red in figure 8). We wanted to ensure a diversity in the transmission line connection and selected feeders that originated in substations fed from different line sizes.
- Diversity in pending DG capacity. To highlight how increased DG capacity affects the ability to absorb reactive power, we selected two feeders that had a big difference in the pending PV they were to receive, as seen in figure 9.

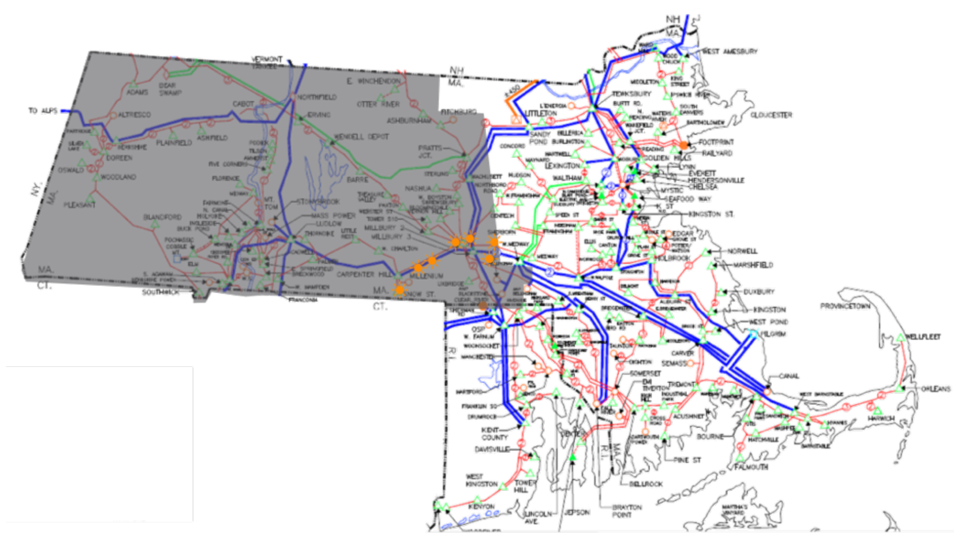

Figure 8: Seven candidate sites (orange) and their location on the Massachusetts electric system map

In this study, the two feeders labeled in this work as F1 connected to the first substation (S1) and F2 connected to the second substation (S2)

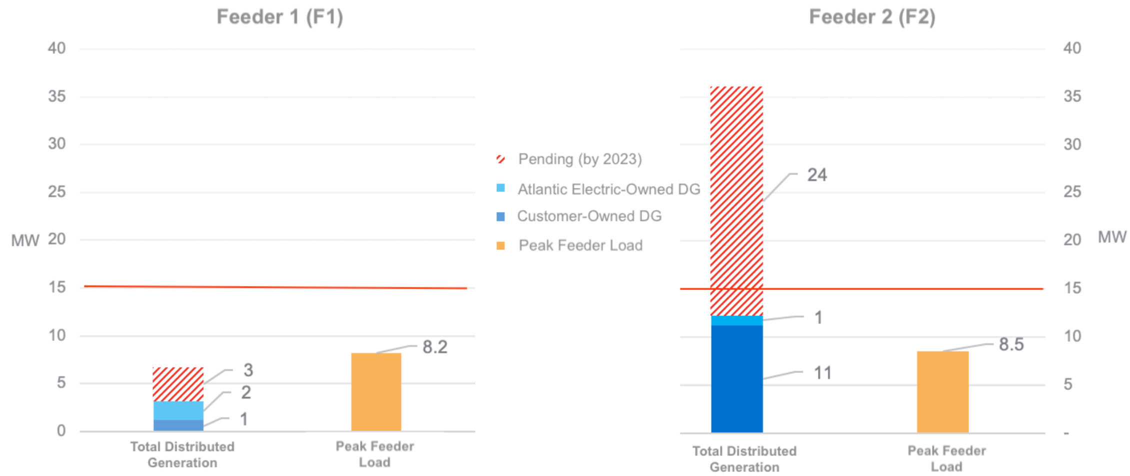

Figure 9: Comparison of the generation levels of F1 and F2

Framing the solution for the problem at the entire substation level as a "virtual shunt reactor" assumes participation of DG across all the feeders connected to substation. However, for this project, while assuming DER on all participating feeders of a substation would absorb reactive power, we only analyzed the distribution system impacts on the one study feeder within each substation. Hence, the precise location and count of DER sites on all feeders other than the study feeder were not important as we simply aggregated the DER connected to all the other feeders at the substation level. The aggregated capacities were bucketed into: Small PV, Large Existing PV, Large Pending PV, and Load. These categories were chosen based on important classifications that would later affect the modeling choices of what qualifies as a "participating" DER site.

This simplification does not compromise on the quality of the study of distribution system impacts on the study feeder since the voltage regulation of any distribution feeder is always controlled separately from the substation voltage control or any other feeder connected to it. To summarize, our proposed methodology assumes that if any feeder were to be studied within a substation, all other feeders could be aggregated into an equivalent circuit of loads and generation to account for their reactive power absorption contribution without having to study them in detail. This is explained in more detail in Section 3.4, "Which DG sites participate in VAR absorption."

Finally, when we modeled the costs of the proposed substation-level solution, we created a measure, defined as the mitigation scaling factor, to account for the scaling of our findings of the study feeder's distribution system impact to the other feeders within a substation. This is explained in more detail in Section 4.2, "Analysis Parameters."

Figures 10 and 11 are visual representations of the two feeders under study, F1 and F2. While tables 2 and 3 detail substations, S1 and S2, showing the generation and load capacities of each.

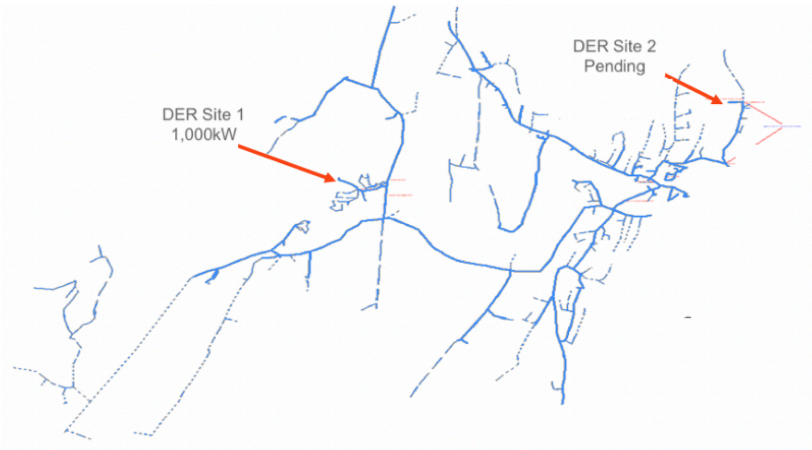

Figure 10: Feeder 1 geographic map showing locations of large DER

Substation 1, Feeder 1	Generation	Large DER Site 1 (existing)	1.0MW
	Generation	Large DER Site 2 (pending)	3.7MW
	Generation	Small DER	1.3MW
	Load		8.2MVA
Substation 1, Parallel Feeders	Generation	Large DER (existing)	16MW
	Generation	Large DER (pending)	23MW
	Generation	Small DER	9.5MW
	Load		15.8MVA

Table 2: Substation 1 load and generation details

Figure 11: Feeder 2 geographic map showing locations of large DER

Substation 2, Feeder 2	Generation	Large DER Site 1 (existing)	1.0MW
	Generation	Large DER Site 2 (existing)	5.0MW
	Generation	Large DER Site 3 (existing)	1.0MW
	Generation	Large DER Site 4 (existing)	1.0MW
	Generation	Large DER Site 5 (existing)	1.0MW
	Generation	Large DER Site 6 (existing)	1.0MW
	Generation	Large DER (pending)	21.5MW
	Generation	Small DER	1.4MW
	Load		3.9MVA
Substation 2, Parallel Feeders	Generation	Large DER (existing)	15MW
	Generation	Large DER (pending)	17.9MW
	Generation	Small DER	7.2MW
	Load		28.5MVA

Table 3: Substation 2 load and generation details

3.3. Reactive Power Absorption Targets

During the research phase of this project, Atlantic Electric was in the process of studying the impact of waiting-to-interconnect DG on the transmission system as ordered by ISO-NE. The study had only produced preliminary results for a portion of the DG sites in the area of interest. These results, called the group 1 study, were the first to introduce the problem of lightly loaded transmission lines and the need for induction on the system. The study presented in its preliminary findings the need to install six (6) different shunt reactors on the 69kV and 115kV systems. These shunt reactors were sized as follows:

- Sub A – 6 MVAR
- Sub B – 10 MVAR
- Sub C – 22 MVAR
- Sub D – 25 MVAR
- Sub E – 2 x 6 MVAR reactors

The above information acted as the only source of data from which a range of VAR absorption targets could be made, and that became our reference. From this information, we aimed to absorb reactive power in the ranges of 0 to 25MVAR.

We agree that this might sound extremely ambitious given most substation transformers are rated at 44MVA, meaning that at 24MVAR, we are requesting that a substation utilize more than 50% of its capacity for the absorption of reactive power. However, it is important to note that this truly is optimization to find the maximum reactive power absorption capability of a feeder in the sense that we are phrasing the question to be: What is the maximum reactive power a substation can (technically) absorb without negatively affecting the distribution system? But we do concede that this might not be practical due to operational and economic conditions.

3.4. Which DG sites participate in VAR absorption?

On the question of which DG sites were to participate in VAR absorption, we divided the arguments into three main criteria: DG size, DG status, DG location.

1. DG Size: This criterion is important to set since allowing very small-sized DG, like residential solar PV systems, to participate in a program as such a program was deemed impossible due to the difficulty in communicating data to the thousands of small-sized DG. Additionally, these systems are so varied in their specifications that no single standard would be acceptable for all. For this reason, we wanted to only include large DG sites in VAR absorption. We first defined large according to how the new ISO-NE rule for studying DG under the cluster study as anything 1,000kW or larger. We then realized that the Atlantic Electric has a requirement to install an additional circuit recloser for any site of that size, and so a very large proportion of projects in the Atlantic Electric area are sized to be just under 1,000kW. We believed that these sites should be included for what we qualify as “large” and dropped the cut-off to 950kW.
    - Small sites: <950kW
    - **Large sites: >=950kW**

2. DG status: The argument here is that inverter technology changes rapidly, and while smart inverter functions were commonplace for inverters installed within the past 5 years, there was no requirement for their installation. If a DG site were to participate in VAR absorption, then we had to assume it was either capable of advanced inverter functionalities or be retro-fitted to do so. To avoid retrofitting costs, we wanted to study the cases where only pending DG sites were allowed to participate. A second case was studied for when all sites were to participate, assuming retrofitting for existing sites that need retrofitting. Additionally, another complication with existing sites is that their interconnection agreement with the utility is already signed and approved, leaving little room for adding a clause for compensation for grid support functions, which we assume would be needed in interconnection agreements on pending sites.
    - **Pending sites: those *not* connected by Dec 2018 but submitted interconnection request**
    - All sites: all sites, existing and pending.

3. DG location: This criterion allows for the consideration of all DG on a substation, including those on parallel feeders to the study feeder, to participate in reactive power absorption.
    - Feeder: sites on the study feeder only
    - **Substation: sites on the parallel feeders to the study feeder on the same substation**

3.5. Results

After a series of iterative modeling, our results show that Atlantic Electric's S1 and S2 have a substantial amount of reactive power absorption capability with minor mitigation effort additions to their current setup.

As described in section 3.1, each of feeder 1 and feeder 2 were cycled through a series of scenarios for MVAR absorption targets, DER generation levels, and load consumption levels. Additionally, as described in section 3.4, both feeders were studies under different conditions of DER participation of feeder vs. substation, and all PV vs. pending PV.

To present these results, the charts that follow all maintain the same layout of a combination of 20 smaller "mini-plots" laid out in a 4x5 matrix. An example of one of these smaller plots is seen in figure 12. In figure 12 we see, that at loading level 100% and generation level 0%, for each VAR condition (colors), the number of overloads that this feeder observes for each amount of MVAR requested. From here, a similar plot is created for each of the 25%, 50%, and 75% loading level as well as the 25%, 50%, 75%, 100% generation levels and placed in a 4x5 matrix chart where the rows represent the four loading levels, and the columns represent the five-generation levels.

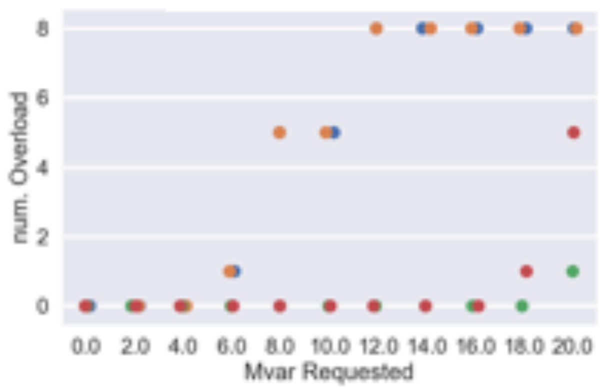

Figure 12: Sample output result representing the number of overloads

When analyzing distribution feeders, multiple electrical load flow result categories were observed. If any of these results exceeded the allowed limits per Atlantic Electric's standards, it was deemed a violation. These result categories include:

- Additional MVAR Capability Needed [MVAR]
- Real Power Curtailment [MW]
- Substation Apparent Power [MVA]
- Substation Power Factor [pf]
- # of additional substation regulator tap changes [no.]
- # of Overloads [no.]
- Thermal limit of conductor and equipment [Amps]
- # of Under-voltages [no.]
    - V_dist < 0.95 p.u.
- # of Over-votlages [no.]
    - V_dist > 1.05 p.u.

3.5.1. Substation 1 and Feeder 1

Substation 1 is an example of a lightly saturated circuit. For this reason, F1 showed that more MVAR capability was needed to be added as early as when 4MVAR were requested to be absorbed, as seen with all scenarios in figure 14. For this reason, we quickly realized that relying on the VAR capability of a single feeder was never going to be enough to achieve the large (>10MVAR) absorption targets we were seeking so we started to focus more on the two conditions that included the VAR capability of the parallel feeders: the "Sub: All PVs" and "Sub: Pending PVs."

Out of all the results plotted, the two that provided the strictest constraints were the number of overloads observed and the number of under-voltage violations.

Overloads happen because as the amount of MVARs requested is increased, more power has to flow through the system; hence more elements observe overload violations. This is particularly a problem in the higher load scenarios (the bottom row of the matrix).

Under-voltages happen because the additional absorption of reactive power, while decreasing the voltage on the transmission system to a desired amount, can decrease the voltage on the distribution level to level below that is acceptable. This is particularly a problem with higher load scenarios (the bottom row of the matrix).

Starting with overloads, as seen in figure 15, we see that the maximum absorption level with no violations across all scenarios is 4MVAR, and this occurs during 100% load and 0% generation. These are mostly for the feeder only conditions, which we ignored since more VAR capability will be needed on the feeder to support that case, but violations are also seen by the substation conditions around the 18MVAR mark.

When looking at under-voltages, from figure 16, we see that it is not possible to achieve any reactive power absorption in the current setup for any scenario on feeder F1. We quickly observe under-voltage violations when we request 2MVAR on the system.

To mitigate against under-voltage violations, a voltage regulator was proposed as a mitigation effort for F1. This voltage regulator was sized at 168kVA according to the study results. The location of this voltage regulator was picked at a feeder forking point to allow it to regulate the voltage violations coming from DG sites installed on both of its main branches. A regulator is a relatively cheap addition to the system at $20,000. Figure 13 shows the location of where the voltage regulator was chosen.

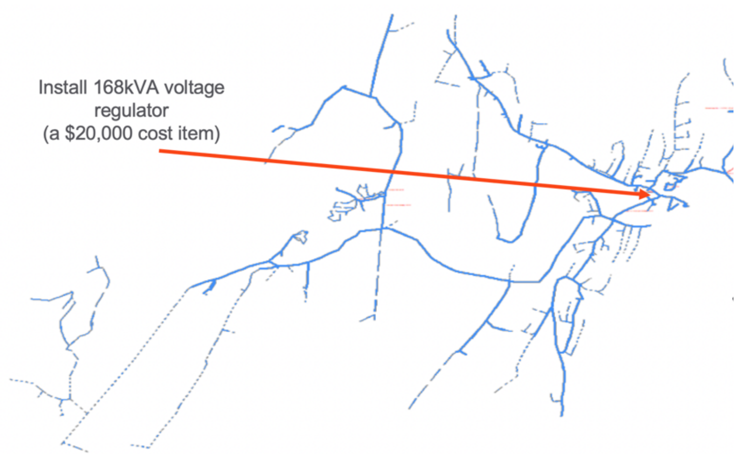

Figure 13: F1's new voltage regulator position on the feeder map

When re-running the analysis, we found that, as seen in Figure 17, F1 can absorb up to 10MVAR requested with no Under-voltage reported in any scenario – for the substation conditions. This, coupled with the previous findings that we can absorb up to 18MVAR with no other violations, concluded that 10MVARs of reactive power was the maximum limit for F1's absorption with the addition of 1 voltage regulator.

Take-away from figure is: across all load, and generation scenarios, the feeder only conditions (blue and yellow) always require additional MVAR capability for any absorption requests >4MVAR

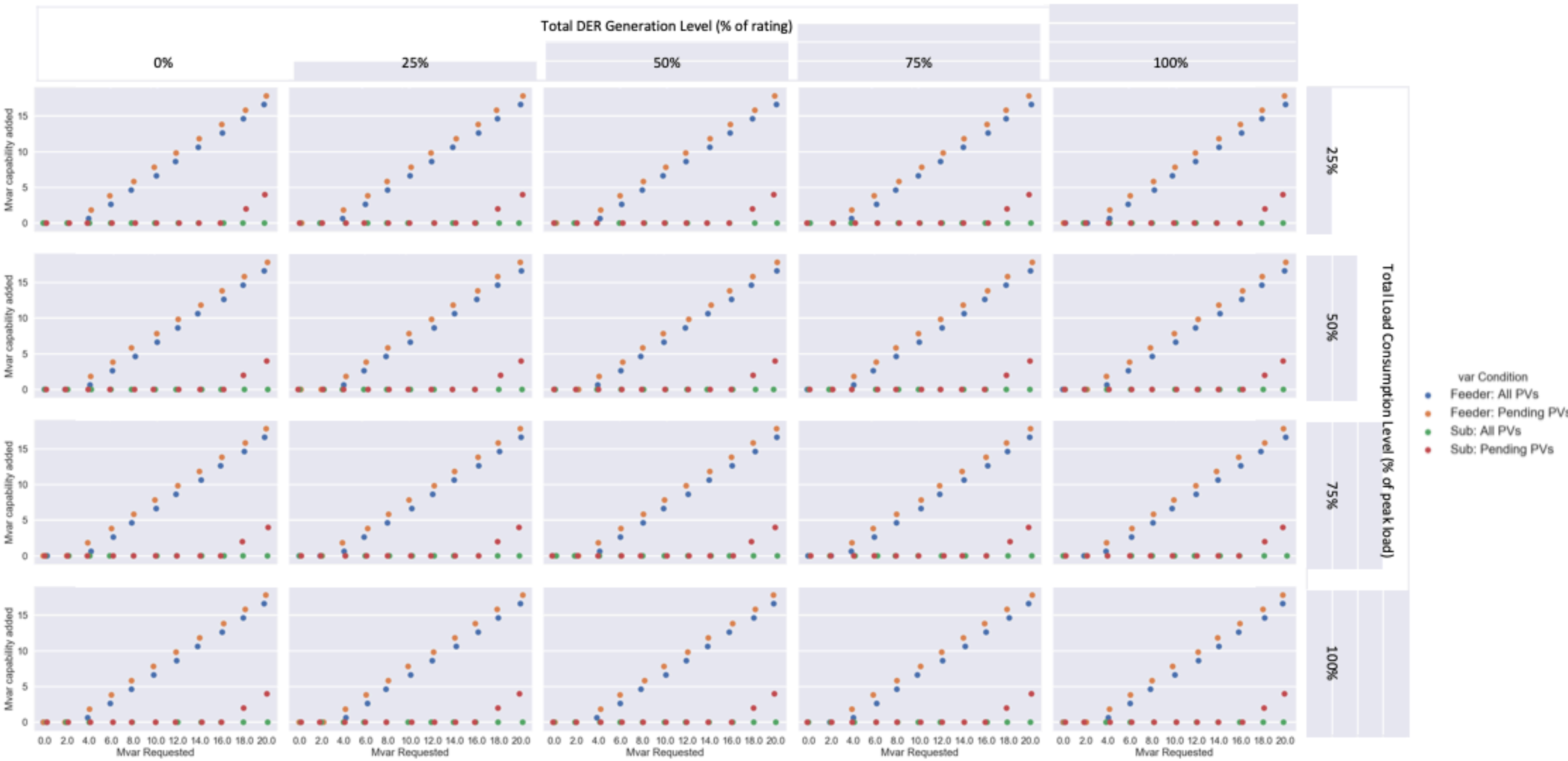

Figure 14: MVAR Capability Added to F1 showing that need for additional MVAR sources in most cases

Take-away from figure is: The largest amount of MVAR absorption that can be achieved before seeing any overloads is 4MVAR – at 6MVAR overloads are seen in the 100% loading, 0% generation scenario (red dashed box).

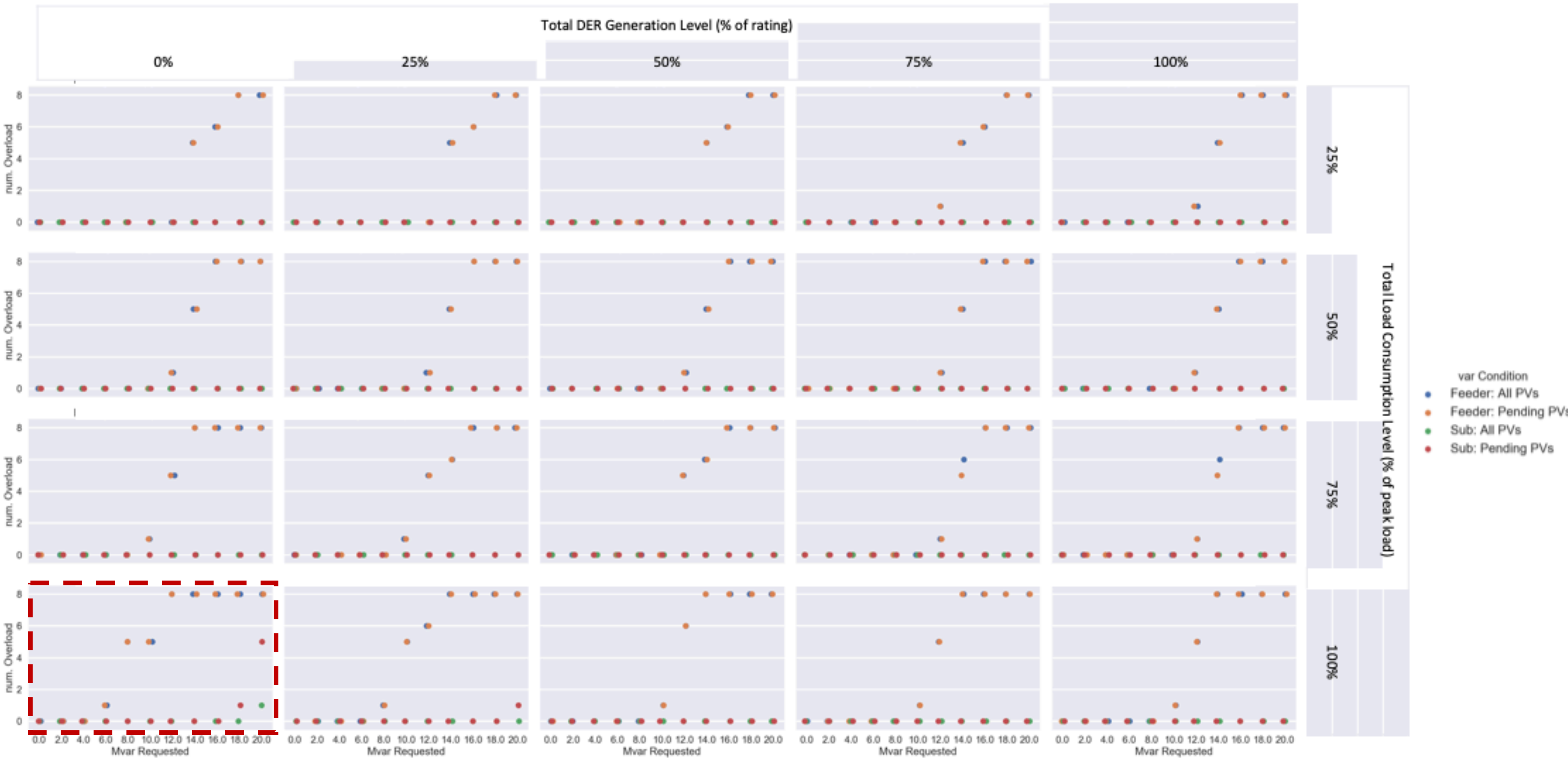

Figure 15: Number of Overloads for F1 showing 4MVAR as the largest possibility

Take-away from figure is: No MVAR absorption is possible without seeing under-voltage violations – Under-voltage violations appear as early as 2MVAR for the 100% loading, 0% generation scenario (red dashed box).

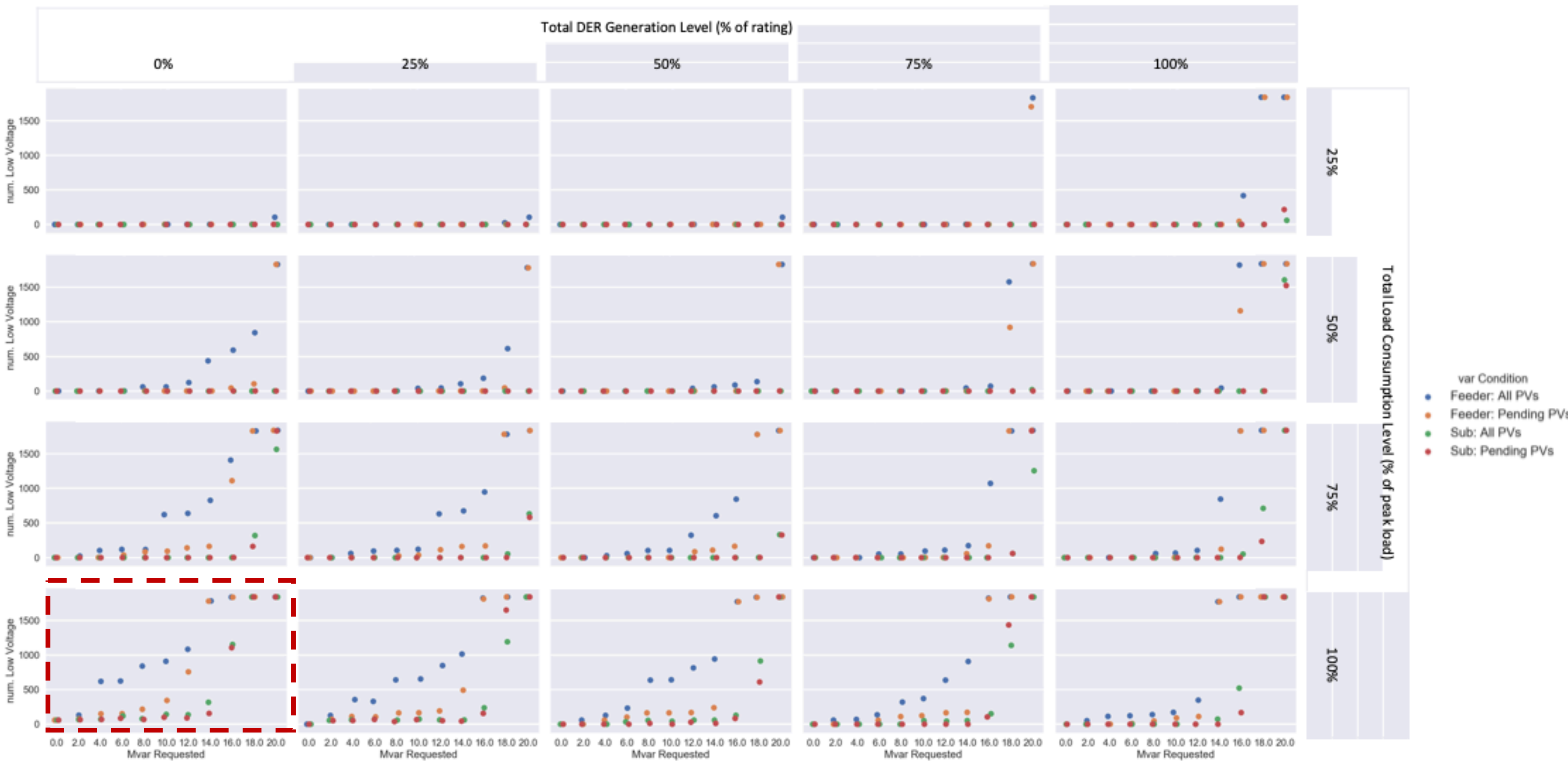

Figure 16: Number of under-voltages for F1. Showing 2MVAR as the largest possibility

Take-away from figure is: After adding a voltage regulator, under-voltage on this feeder don't appear in any scenario until 14MVAR, making 12MVAR the largest possibility of absorption.

Figure 17: Under-voltages on F1 with 168kVA voltage regulator showing 10MVAR as the largest possibility

3.5.2. Substation 2 and Feeder 2

Similar to F1, F2 didn't have enough local VAR capability to support the feeder-only conditions, and so the focus shifted to study the substation conditions. The first thing noted is the number of overloads the system observed. As seen in Figure 19, F2 could take up to 8MVAR before seeing its first overload violations.

An important note here is that results of F2 show 12 overload violations for all the MVAR's requested for conditions with 100% generation. These violations are because the pending PV on F2 is so great that it exceeds the transformer rating of the substation. In practice, not all of the pending PV will be approved for interconnection, but for the sake of this study, we wanted to make sure to include all pending PV. This presented the problem that these pending PV sites create noise in the data by introducing violations not caused by the new VAR absorption efforts of this project, but rather from the initial conditions. It is for these reasons that the assumed base for comparing meaningful overload violations for F2 is 12 violations.

When looking at under-voltages, as seen in figure 20, 12MVAR was the maximum allowed request with no violations. With no other meaningful violations to present, it is important to note the S2 has the ability today to absorb up to 6MVAR of reactive power with no impact on the distribution system.

However, we wanted to stretch the limit to see how much reactive power absorption could be achieved with minimal mitigation efforts. To mitigate against overloads and Under-voltages, we introduce 1,100ft of reconductoring and a 416.3kVA voltage regulator. Re-conductoring is the installation of a larger cable size to allow more current to pass through the cable without overloading. The location of these two mitigation efforts is seen in figure 18.

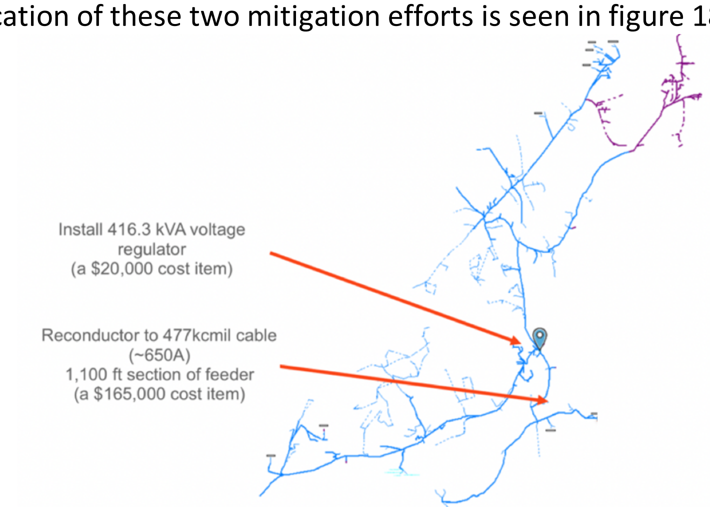

Figure 18: Location of mitigation efforts for F2

Figures 21 and 22 represent the new overload and Under-voltage results for F2, respectively. We see from Figure 21 that we can now achieve up to 24MVAR, and from Figure 22 that we can now achieve up to 28MVAR.

Take-away from figure is: The largest amount of MVAR absorption that can be achieved before seeing any overloads is 12MVAR – at 14MVAR overloads are seen in the 25% loading, 100% generation scenario (red dashed box).

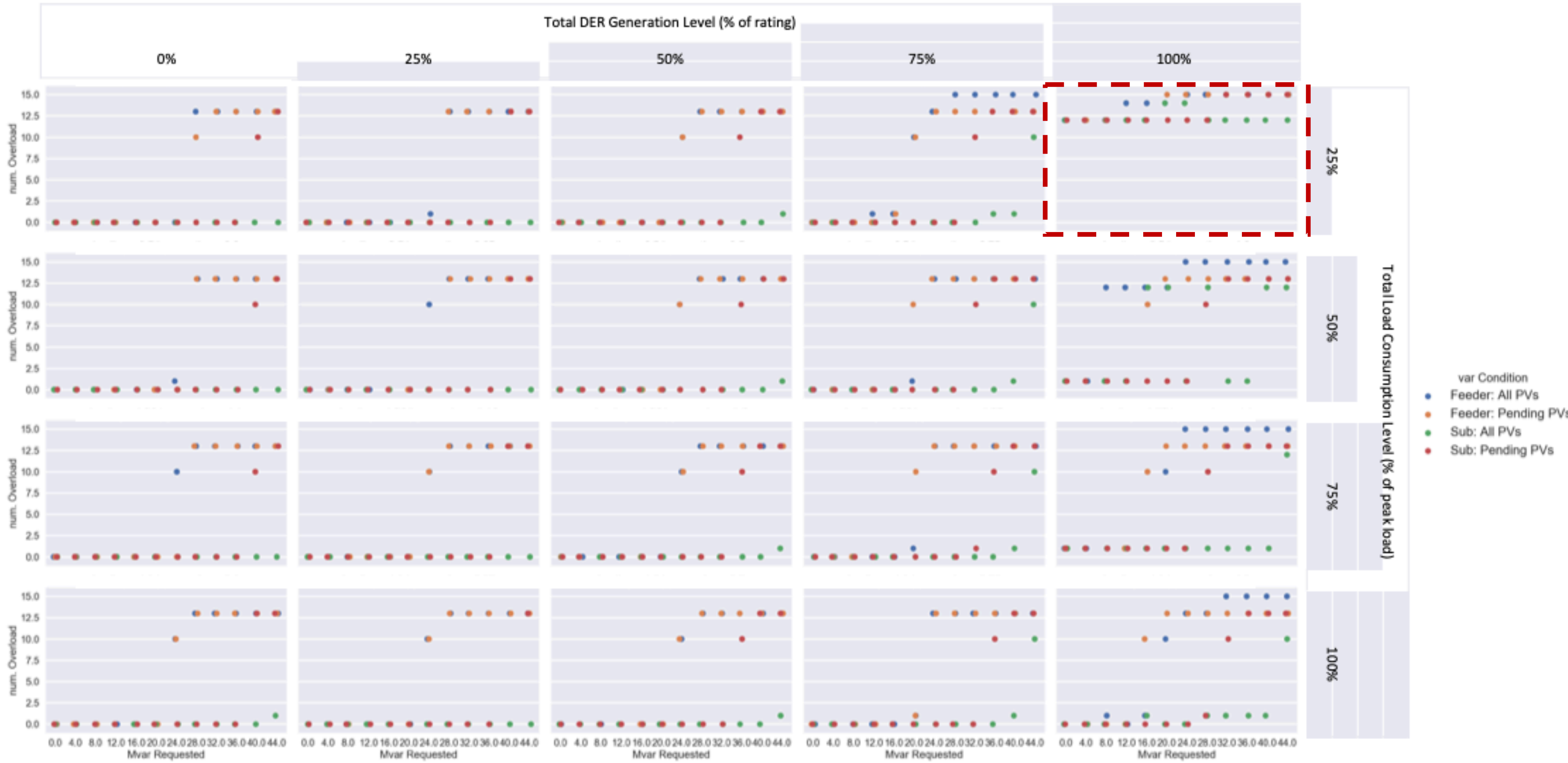

Figure 19: Overload violations for F2 showing the ability to absorb up to 6MVAR

Take-away from figure is: The largest amount of MVAR absorption that can be achieved before seeing any under-voltage is 8MVAR – at 12MVAR under-voltages are seen in the 100% loading, 0% generation scenario (red dashed box).

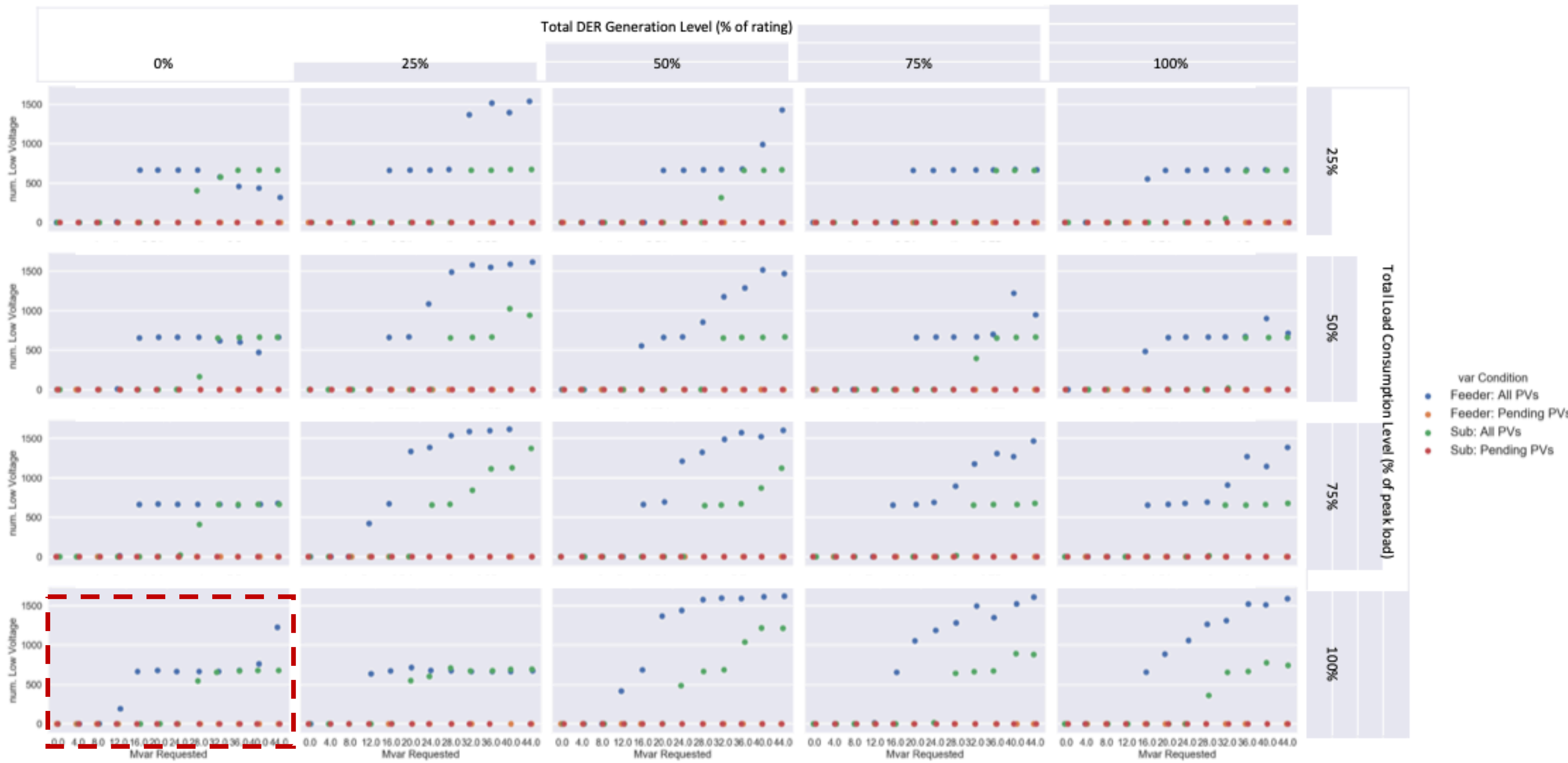

Figure 20: Under-voltage violations for F2 showing the ability to absorb up to 12MVAR

Take-away from figure is: After reconductoring, overloads on this feeder don't appear in any scenario until 28MVAR, making 24MVAR the largest possibility of absorption.

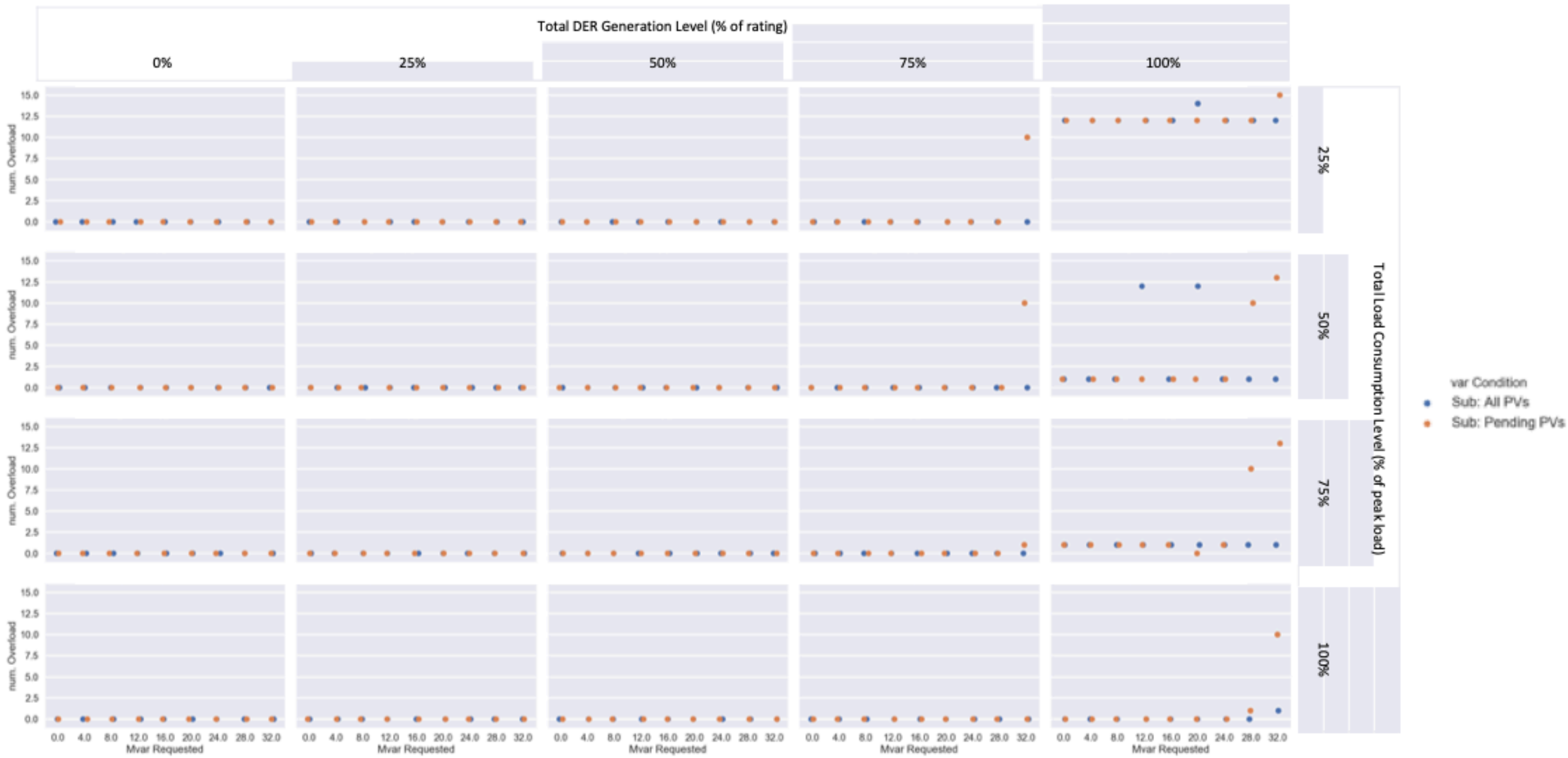

Figure 21: Overload violations on F2 after adding 1,1000ft of reconductoring showing 24MVAR possibility

Take-away from figure is: After adding a voltage regulator, under-voltages on this feeder don't appear in any scenario until 30MVAR, making 28MVAR the largest possibility of absorption.

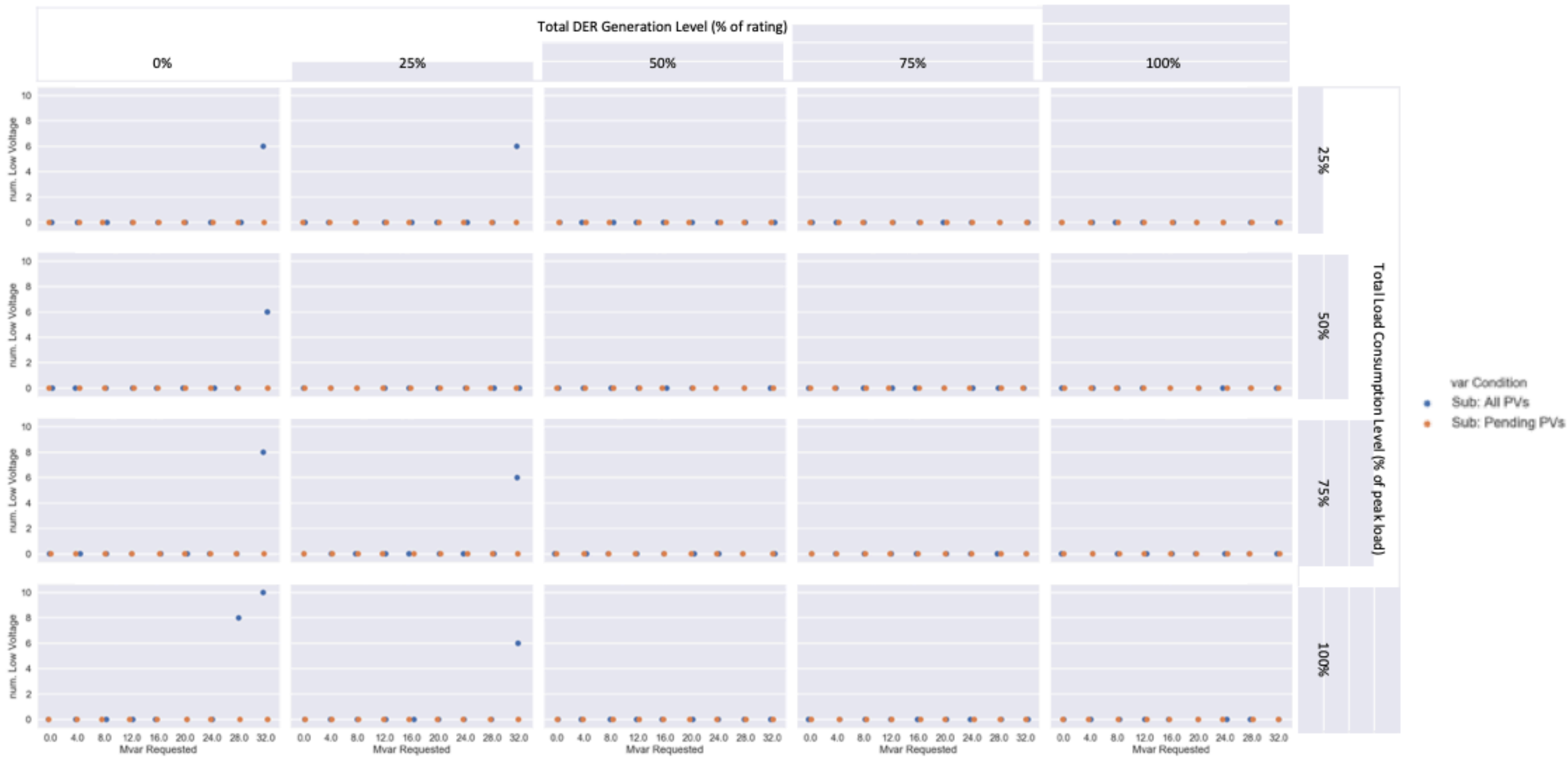

Figure 22: Under-voltages for F2 with 416.3kVA voltage regulator showing 28MVAR possibility

3.6. Modeling Conclusions

Table 4 summarizes the modeling results made thus far.

Substation	VAR capability w/ no mitigation	VAR capability w/ mitigation	Type of mitigation	MW of DER needed	No. of DER sites needed
S1	0	12MVAR	-168kVA voltage regulator	44.65	24
S2	12 MVAR	24 MVAR	-413.8kVA voltage regulator -1,100 ft reconductoring	69.11	30

Table 4: Summary of results from modeling two representative feeders

Results are based on a PV participation scenario of:

- Only Large PV (950kW+) can participate in VAR voltage control
- All (existing + pending) PV will participate
- All Substation PV (including PV on parallel feeders) will participate

4. **Cost-Benefit Analysis**[6]

This chapter focuses on highlighting the value proposition for using smart inverters. Value is defined in this context through a financial impact analysis where costs and benefits are calculated separately and joined to form a cost-benefit analysis that identifies the conditions at which the largest payoff would come.

4.1. Costs

Costs studied are only those that relate to the technical requirements of the purposed system. To avoid making a judgment on non-technical factors, we ignored costs that come with change management and the stakeholder's ability to implement the new purposed system into their operations' standards and procedures. Furthermore, costs associated with any regulation changes or commercial term adjustments are also not accounted for.

4.1.1. Equipment Costs

As a base case for the analysis, a shunt reactor install was considered. This is what we labeled in Chapter 2 as the "traditional solution" to the problem. The advanced inverter solutions are direct 1-to-1 replacement of the same impact on the system, but they come with a different cost. Table 5 details the costs of installing shunt reactors as inputted into the model. Shunt reactors were assumed to have a 40-year lifespan.

	Description	Unit	Cost
Shunt Reactor[7]	Materials, Installation	per MVAR	$13,000
	Reactor Pad containment and foundation	per each	$4,200,000
	Annual Maintenance	per year each	$5,000

Table 5: Cost estimate for shunt reactors

As detailed in Chapter 3, mitigation factors were introduced to increase the "reactive power hosting capacity" of feeders and allow them to reach higher absorption targets without violations on the transmission system. Equipment costs represent the costs of installing these mitigation factors, as seen in table 6.

	Description	Unit	Cost
Reconductor to 3ø 477	Materials, Installation	per 1 mi	$792,000
	Annual Maintenance	per year each	$2,000
New Regulator[8]	Materials, Installation	per each	$20,000
Regulator Upgrade[9]	Materials, Installation	per each	$20,000

Table 6: Cost estimate for mitigation factors

Data from table 5 and table 6 above are best estimates from Atlantic Electric as of December 2019 obtained through internal communication.

---

[6] Work in this chapter was made in collaboration with the Electric Power Research Institute (EPRI) Program P174 - Enabling Integration of Distributed Renewables

[7] Costs are averaged across estimates of reactor sizes and types (oil vs dry)

[8] For simplicity of analysis, an average regulator cost was assumed regardless of size

[9] From increased tap operations: assumes the regulator operates twice as often and fails in half the time it would otherwise. Represented as the difference in annualized cost between the original 25-year asset and a 12-year asset

4.1.2. Opportunity Cost of Curtailed Energy

The opportunity cost of curtailed energy is a cost item that represents the value lost from limiting real power outputs of DG inverters. Energy was valued for this problem specifically in the Massachusetts case where wholesale market rates define the cost, as seen in table 7.

Average Marginal Cost of Energy[10]	\$20.00/MWh
Average Marginal Cost of Renewable Energy Certificate[11]	\$30.84/MWh
Total Marginal Energy Cost	\$50.84/MWh[12]

Table 7: Cost estimates for curtailed energy

Note that the total energy cost estimate of \$50.85/MWh is significantly lower than the SMART tariff rate of \$188/MWh, which is what the DG developers are paid for the energy they produce. We studied the total energy cost and not the SMART tariff payout because this analysis takes the total economic perspective and values curtailed PV energy at the market rate as to avoid any judgment of a policy initiative like the SMART tariff – it would be up to the utility and its regulators to account for the difference.

4.2. Analysis Parameters

When considering the costs and benefits, we had to create two parameters to more accurately capture the nuances of real-life deployment of the results. The definitions of these analysis parameters are the following:

Mitigation scaling factors: This relates to the point mentioned in Chapter 3, where only the study feeders' impact, and consequently, the mitigation factors needed, were studied even though the calculation was made for DG sites on parallel feeders to contribute reactive power absorption.

To account for this, the mitigation scaling factor was created as an input to the model. The range that the mitigation impact factor was allowed to fluctuate within was defined by calculating a linear relationship between the base case and every other edge case. The base case for Substations 1 and 2 were Feeders 1 and 2 respectively, and then by knowing how the other parallel feeders on those two substations differed from F1 and F2, we approximated the range of mitigation scaling factors which was found to within a low of: 2x and high of 8.5x. We believe that all scaling factors will fall in this spectrum, and hence a high and low estimate for the cost-benefit analysis can be derived out of these numbers.

DC/AC ratio: DC/AC ratios represent the difference in sizing of the power output of a solar array compared to its inverter. In practice, it is common to oversize the DC system compared to

[10] Based on averaged hourly (7am-5pm) ISO-NE Wholesale Price LMP at .H.INTERNAL_HUB. Source: ISO-NE [11]
[11] Based on averaged MA Class 1 REC Index 2020. Source: S&P Global Market Intelligence [36]
[12] Based on average pay-out for 1MW+ solar PV site. Source: Internal communication with Atlantic Electric SMART program administration

the AC system in order to capture more energy over a day's production values. This, in turn, means that the higher the DC/AC ratio is, the more energy has the potential to be curtailed (energy curtailment is an important cost input to this project's CBA model). In industry, a DC/AC ratio of 1.3 is the most common; hence a low/high estimate of 1.0/1.5 was assumed.

Figure 23 shows five daily power production curves (as a % of their AC rating), averaged over an entire year, calculated based on the solar resource available in Massachusetts for the typical size of solar PV farm found in Massachusetts. The effect of the DC/AC ratio on energy curtailment can be best seen here, whereas the DC/AC ratio increases, there is more time where the production is closer to or meets 100% of the AC rating. If we, as proposed in the invert-based solution, assume that in the reactive power absorption mode, the DG site is not allowed to produce more than 80% of its rated power, then we see a variety of expected maximum curtailed energy estimates (the orange area) depending on the DC/AC ratio of the plant. For a 1.3 DC/AC ratio, we expect ~7.8% of energy production to lie above that 80% cutoff.

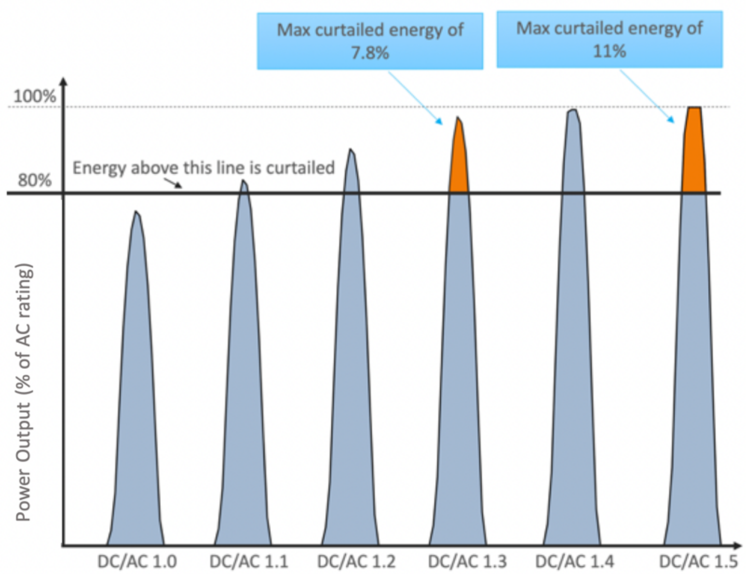

Figure 23: DC/AC ratio's effect on the reported power output of PV plant

While 7.8% curtailed energy may sound like a lot of lost energy, it is not practical to see that amount of curtailment at all times. This is because the 80% limit on real power production is governed by the amount of requested MVARs through a relationship known as Power Factor. Power factor is the ratio of real power (W) to apparent power (VA). Apparent Power is the square root of the sum of the squares of real and reactive power, as seen in the equation below. Therefore, a lower reactive power request will significantly increase the power factor, which in turn reduces the energy curtailment.

$$pf = \frac{P}{S} = \frac{P}{\sqrt{P^2 + Q^2}}$$
$$Where:$$
$$pf \text{ is power factor}$$
$$P \text{ is real power}$$
$$S \text{ is apparent power}$$
$$Q \text{ is reactive power}$$

Figure 24 shows different values for inverter power factors at various MVAR Request values for the S1 and S2 substations (green and blue, consecutively) – this is a simple calculation using the above equation, where P is the amount of real power from the participating solar sites.

As seen in Figure 24, we only observe a worst-case scenario of pf=0.94 when requesting 24MVAR (the amount defined per Chapter 3 for Substation 2).

It is important to note that the calculations made to produce figure 24 account for the specific PV participation scenario mentioned in Section 3.6, summarized again:

- Only Large PV (950kW+) can participate in VAR voltage control
- All (existing + pending) PV will participate
- All Substation PV (including PV on parallel feeders) will participate

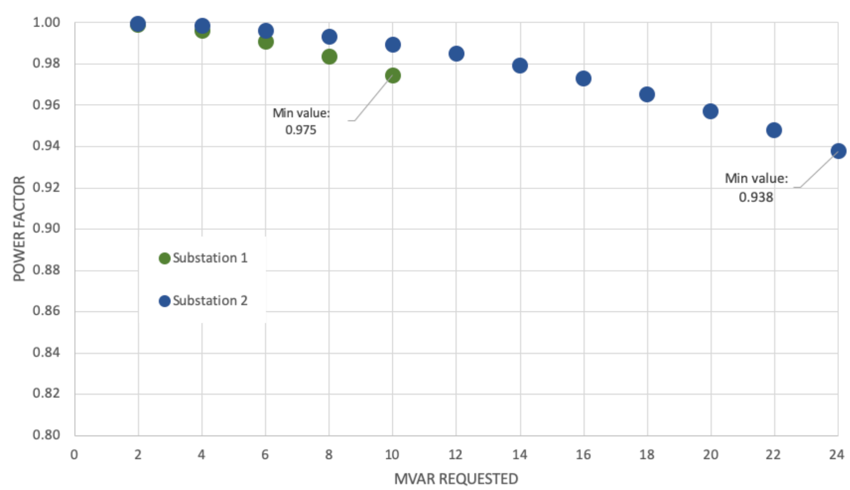

Figure 24: Requested reactive power's effect on inverter output power factor

With this in mind, then from Figure 25, we learn that a 0.94 power factor would result in a worst-case of only 2.5% energy curtailment rate at a 1.5 DC/AC ratio. Figure 25 plots the calculated curtailed energy (as a % of total energy) at every power factor input for a variety of DC/AC ratios.

A "line of best fit" using a third-order polynomial was used to calculate curtailed PV energy as a function of the power factor. This was done for each DC/AC ratio. For example for a 1.5 DC/AC ratio and a PV Capacity Factor = 30%, the polynomial estimation is: $\text{Curtailment } (\% \text{ of total}) = 5.6x^3 + 41.5x^2 - 147.4x + 99.7 - \textit{ where x is the power factor}.$

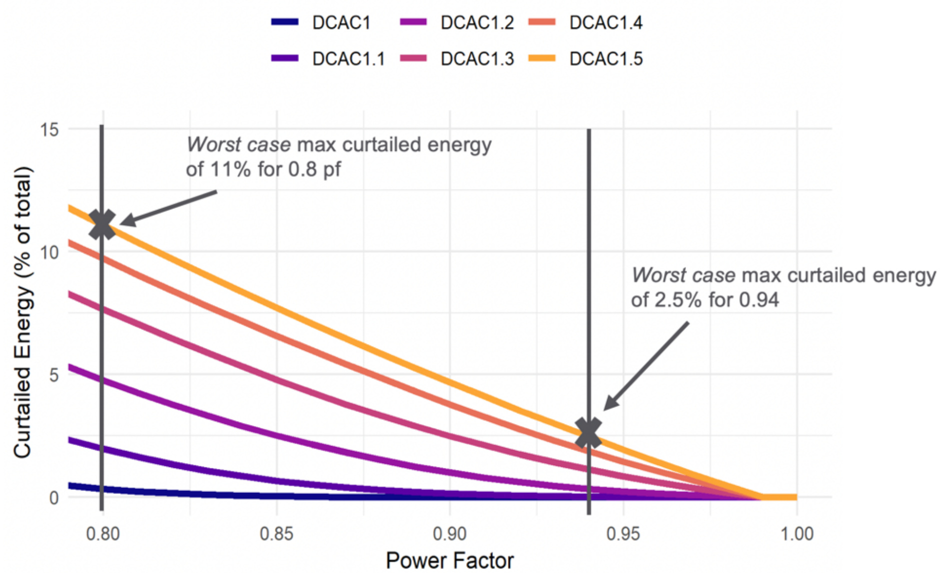

Figure 25: Power factor's effect on the amount of curtailed energy

This, however, is still a very conservative estimate for curtailed energy since it assumes that the reactive power request is always on when the DG is generating at its rated output. In normal operations, PV sites, due to their bell-shaped production curves, would only generate beyond 94% of their rating for a few hours around midday at best, making the actual curtailed energy even lower.

We would have been able to generate a much more refined estimate for curtailed energy had we accounted for the limited time when overvoltage at the transmission line was an issue, and the smart inverter system would have to be activated. However, due to time and data-access limitations of this project, it was assumed sufficient to assume that VAR absorption mode was always on, and hence a worst-case energy curtailment scenario of 2.5% was used. Had we accounted for only the times when Var absorption mode is *needed*, we expect an even lower energy curtailment factor.

4.3. Results

To compare the results of the traditional solution against the newly-purposed inverter-based solution, we pitted the scenarios against each other, where:

1. Base Case Solution: Installing the shunt reactors (shunt Reactor),
2. New Solution: Utilizing the DG smart inverters according to the PV deployment scenario mentioned in Section 3.6 summarized again:
    - Only Large PV (950kW+) can participate in VAR voltage control
    - All (existing + pending) PV will participate
    - All Substation PV (including PV on parallel feeders) will participate

The costs for each scenario were annualized over their expected lifetime, where equipment depreciation was factored into the costs. The final results were displayed in Annual Savings $USD/year value.

For the shunt reactor solution, only the costs in table 5 were considered. For the smart inverter solution, the following cost items were included: first, the mitigation factors as arrived to in Chapter 3 and as detailed in table 6 were included; second, the curtailed energy costs as discussed in Section 4.1.2; and third, the cost of accelerating the life of the existing substation voltage regulators.

When comparing the added costs of deploying smart inverts vs. the base case, the cost difference between the two was labeled as a “Comms/Controls Cost Ceiling” for the installation of the controls and communication system as detailed out in Chapter 2. The reason a cost ceiling approach was used was because of the unreliability of information around the actual cost of installing a DERMS-like system. Even with a detailed bill of materials as clarified in section 2.2.1, the scale and breadth of how this system is deployed significantly affects the total cost. Hence, we deemed it was better to de-bias the results by keeping the installation cost a floating cost ceiling value. Note that we will be using the term “cost savings” to refer to the Comms/Controls Cost Ceiling value.

While calculating the costs for both solutions, a different result was computed for each combination of the following factors:

- Substation (S1 or S2)
- Mitigation scaling factor (2x to 8.5x)
- DC/AC ratio (1.0 to 1.5)
- Reactive power absorption target (2 to 24 MVAR)

4.3.1. Substation 1

For S1, we found cost savings (Comms/Controls Cost Ceiling) in the range of $222,000/year to $325,000/year. Along with a variety of input options to the model, S1 maintained that the smart inverter solution was always better than the shunt reactor solution.

Figure 26 shows the most extreme of input combinations for S1, where:

- Mitigation scaling factors = 8.5x (maximum)
- DC/AC ratio = 1.5 (maximum)
- Reactive power absorption target = 12MVAR (from Chapter 2 - maximum)

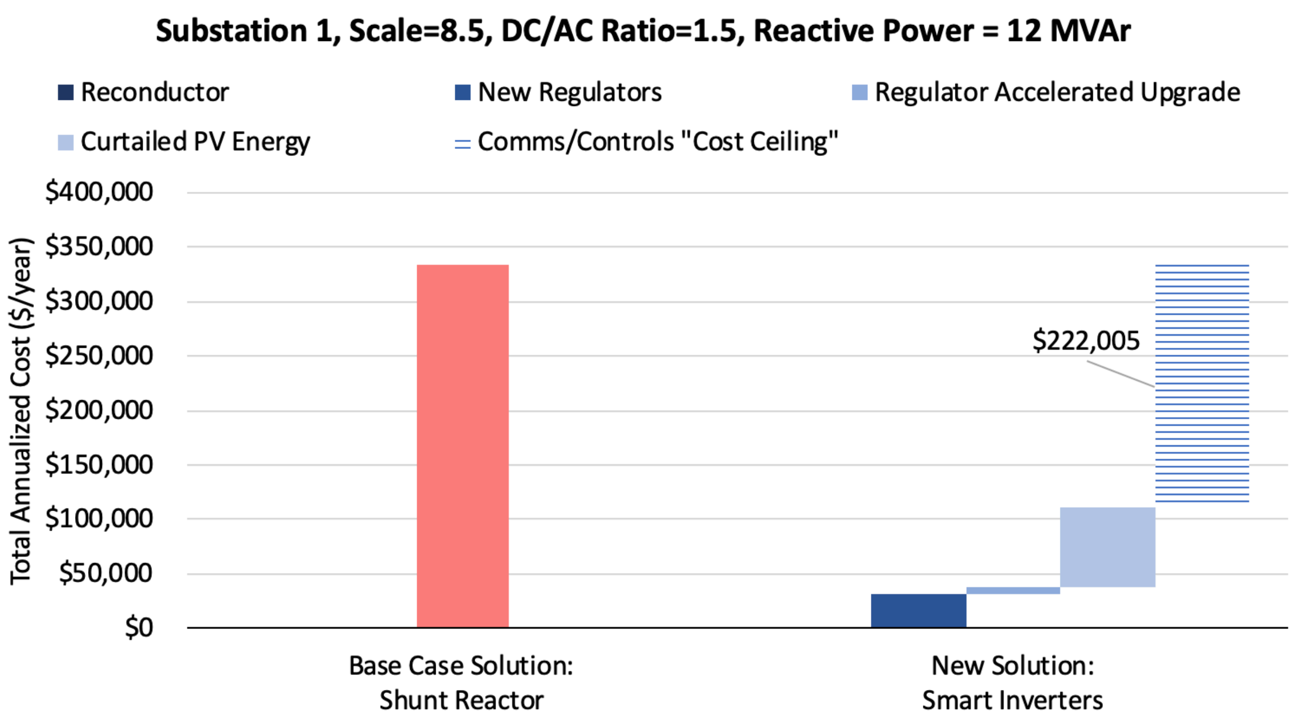

Figure 26: S1 CBA extreme-case results

4.3.2. Substation 2

For S2, the results were less conclusive. We found cost savings (Comms/Controls Cost Ceiling) in the range of -$36,000/year to $330,000/year. Negative results here mean it is cost-prohibitive to implement the smart inverter solution compared to the base case.

The majority of the costs behind the smart inverter solution come from the cost of energy curtailment, which, as we describe in section 4.2, is a conservative over-estimate for real implementation. Hence, with a refined energy curtailment estimate, we still expect the smart inverter solution to out-perform the base case on costs.

Figure 27 shows the CBA results for input combinations for S2 as following:

- Mitigation scaling factors = 8.5x (maximum)
- DC/AC ratio = 1.5 (maximum)
- Reactive power absorption target = 12MVAR (from Chapter 2 - maximum amount of MVAR requiring no mitigation factors)

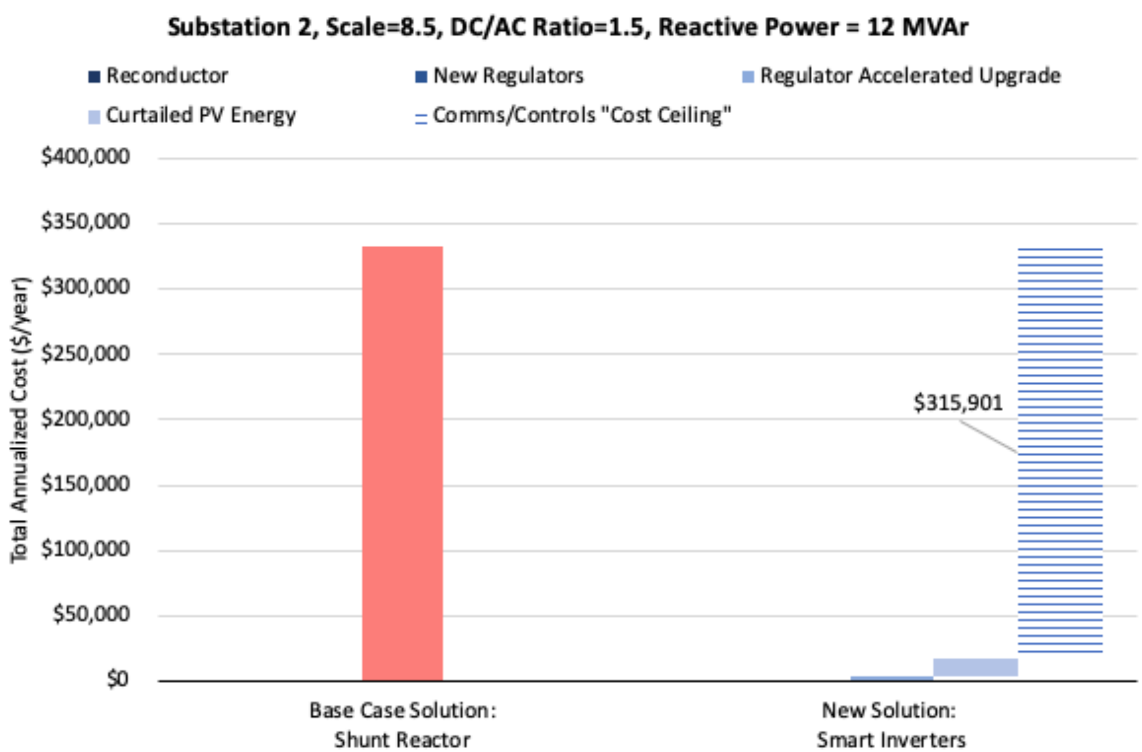

Figure 27: S2 CBA mid-range-case results

However, these results don't hold well when expanding to the full recommended settings from Chapter 3 of 24MVAR, as seen in Figure 29, where the negative cost ceiling represents a cost-prohibitive solution from the inverter solutions. This, as mentioned above, is due to the significantly curtailed energy cost estimates with large reactive power absorption targets.

Figure 28 shows the CBA results for input combinations for S2 as following:

- Mitigation scaling factors = 8.5x (maximum)
- DC/AC ratio = 1.5 (maximum)
- Reactive power absorption target = 24MVAR (from Chapter 2 - maximum)

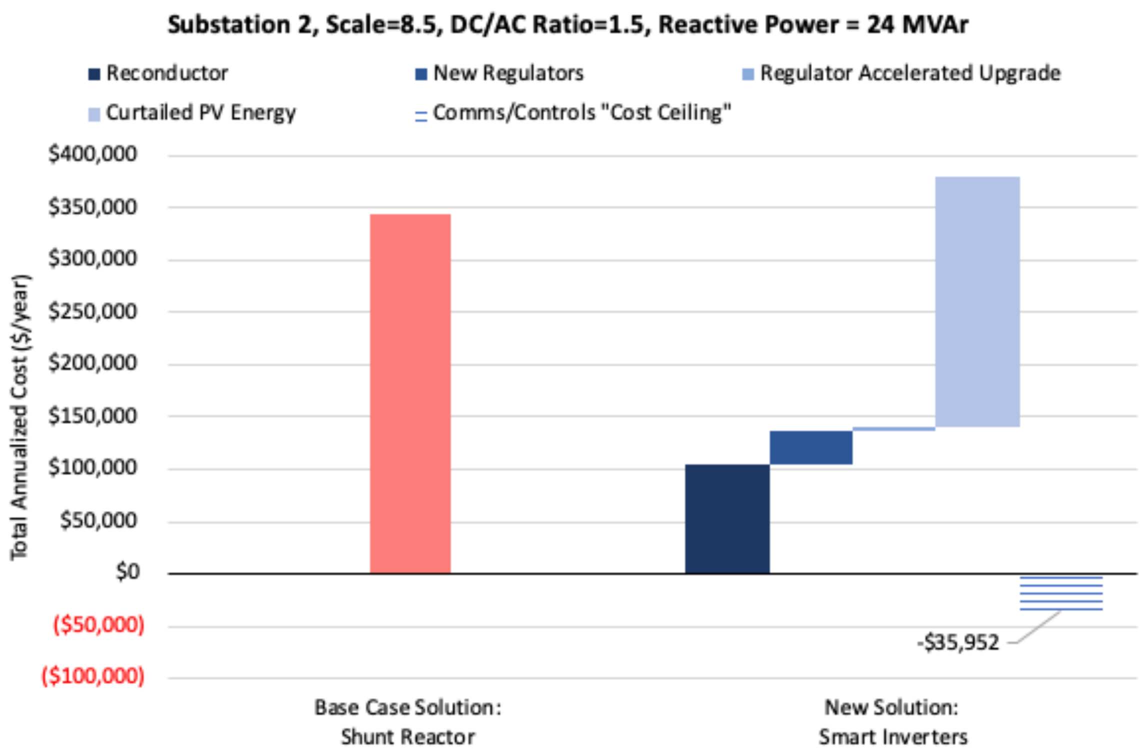

Figure 28: S2 CBA extreme-case results

Finally, in figure 29, we looked at the effect that the reactive power absorption target has on the cost savings value by plotting the cost savings for every MVAR request target for S1 and S2 (green and blue, consecutively). We show this for the high estimate (1.5 DC/AC ratio and 8.5x scaling factor - dark colors in round marks) and for the low estimate (1.0 DC/AC ratio and 2x scaling factor – light colors in square marks).

We observe from figure 29 two important conclusions:

1. Costs are very sensitive to the variations in scaling factors and DC/AC ratios, where the low and high estimates vary significantly, especially with larger MVAR request values, as seen from how the light and dark curves separate apart. This is because large MVAR requests require greater mitigation measures and more energy curtailment, which in turn is further magnified by the mitigation scaling factor and the DC/AC ratio, respectively.

2. The smart inverter solution is a far more economical solution in the lower ranges of MVAR Requests (0-12MVAR). Beyond that, a traditional solution of shunt reactors directly installed on the transmissions system starts to gradually be on par in terms of the costs. It is, therefore, our recommendation to focus any future deployment of the solutions provided in this work on these lower MVAR needs.
   In figure 29, the large disparity between the 12MVAR and 14MVAR data points for Substation 2 High Estimate (dark blue with round marks) is due to the need for re-conducting to resolve overloads in a section of the feeder – this introduces high added costs.

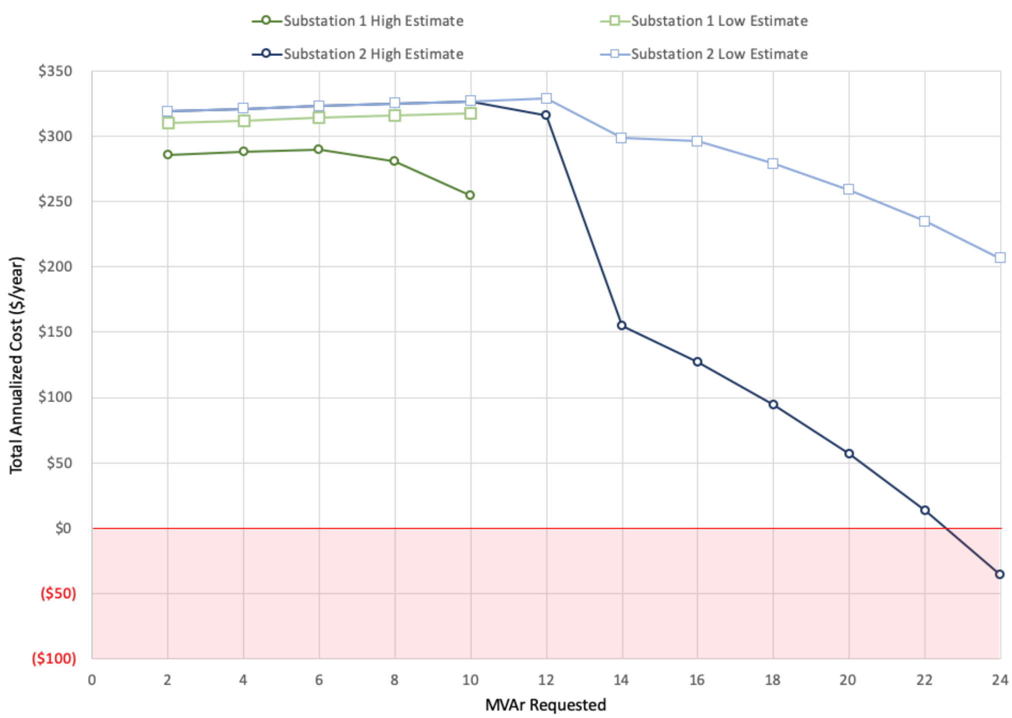

Figure 29: S2 CBA results/MVAR Request for a high and low estimates

While the purpose of this work is to eventually control the voltage on the transmission line, which in turn is what truly defines the amount of MVAR request the system should be designed to handle, we show these results in terms of Annual Savings in $USD as a measure for how economical it is to use this solution for overvoltage reduction.

When choosing to depend on DER inverters and utilize a substation as a "virtual shunt reactor," the sizing of that system has to account for both how much overvoltage reduction is needed as well as if the system is financially implementable.

Finally, it is important to note that these results are solely for two "representative" feeders within a large and complex system, and the findings cannot be generalized without further studies.

4.4. Interactive CBA Model

Due to the myriad of CBA model input combinations for each substation, we found it useful to develop an interactive tool where the user can input the parameters for the system (substation number, mitigation scaling factor, DC/AC ratio, and MVAR requested), and to have the tool produce a graph of the potential cost savings, as seen in Section 4.3.

Figure 30 shows a screen image of the interactive data visualizer with the input parameters on the left and the output plot on the right.

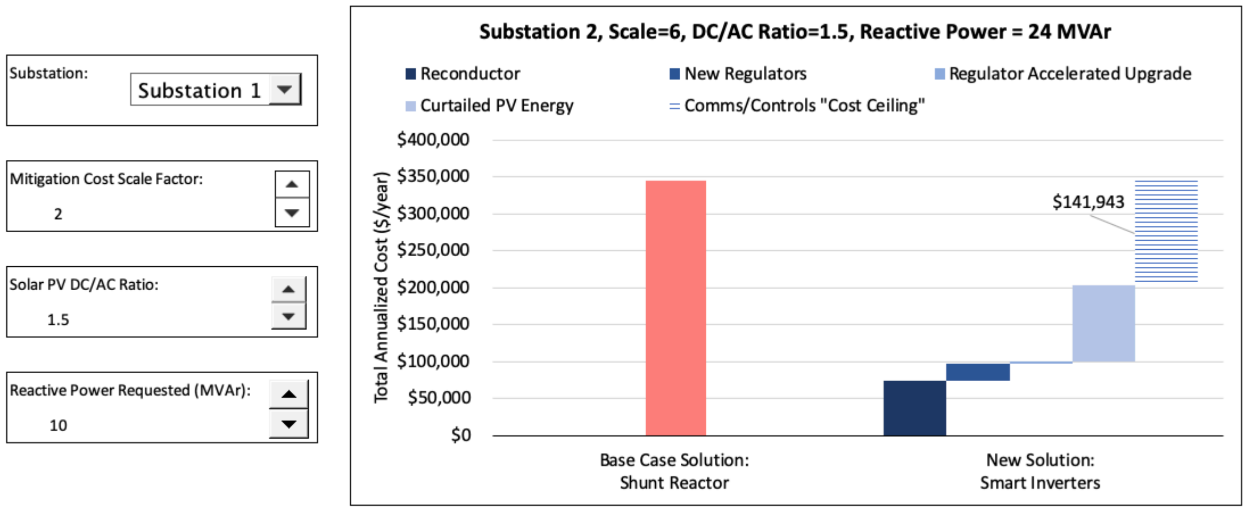

Figure 30: Interactive Data Visualizer for Cost-Benefit Analysis Results

4.5. CBA Conclusions

The first conclusion to draw from the results is that there are significant cost savings to be made under certain conditions of setting up the smart inverter solution. Furthermore, we conclude that the smart inverter solution is much more economical in areas that require 0-12MVAR of reactive power absorption – beyond that, a shunt reactor appears to be close to being at par.

However, the results can be further tuned by working on the following open-end items:

1. Curtailments costs need more refinement. Assuming a 2.5% worst-case scenario, while highlighting the value in the lower MVAR requested categories, appears to be too conservative of an estimate when looking at higher MVAR requests. Analysis of better curtailment analysis could be needed.
2. All PV costs do not account for any retrofit expenses. This is an important cost item that is almost impossible to estimate. DG sites, feeders, and substations vary significantly from one to another, and to understand the true cost of installing smart inverter capabilities on all existing DG sites would have to require a significant survey effort.

Other solutions exist outside of base case. This is important because the comms/control cost ceiling was referenced to the shunt reactor solution even though the utility has other options, such as removing capacitor banks from distribution feeders or entirely disconnecting DER.

This page intentionally left blank.

5. **Conclusions and Future Work**

5.1. System Implementation in Today's Real World

The work hereby presented so far is focused on a technical problem (overvoltage on transmission system) and presents a technical solution (smart inverter reactive power absorption). We understand that to implement this solution in the real-world other challenges need to be accounted for:

- Regulatory challenges: Electric utilities operate in a regulated business model that requires the review and approval of state and federal government on programs such as the one presented. If Atlantic Electric were to see the technical solution feasible, the utility would have to present and defend their proposal to the Massachusetts Department of Public Utilities (DPU) and seek their approval on behalf of the customers they serve.
- Commercial challenges: Electric utilities would have to revise their interconnection agreements and procedures with DER owners. This would be a complicated process that involves the detailing of compensation for the utilization of capacity for reactive power absorption and the distribution of the costs and benefits across beneficiaries on the system. Evaluating commercial terms would also have to account retroactively for systems that have already been connected and future ones that haven't yet.

5.2. Examples of Similar Work from Around the World

Transmission system over-voltage reduction through any devices on the distribution system does not exist at large scale anywhere in the world today, let alone by using DG smart inverters. However, some attempts through innovation pilot projects have started taking this solution more seriously. Two of these attempts described briefly below are: EIRGRID/ESB Network's Nodal Controllers project and National Grid's Power Potential project. Finally, other academic researchers have discussed theoretical applications of TSO-DSO interactions [37], [38].

EIRGRID and ESB Network's Nodal Controllers: The core element of the Nodal Controllers project for Ireland's TSO (EIRGRID) and DSO (ESB Networks) is the installation of interface points at the 110kV/38kV substations that act as controllers for wind plants connected to the 38kV system by taking signals from the system operators. This project's implementation is limited to specific substations that carry no load and only supply power through wind farms. Figure 31 shows a schematic diagram of the Nodal Controllers project in action [39].

The advantages of this approach are the project's flexibility in working in multiple reactive power modes, not just fixed-VAR, as specified in this work, to regulate the voltage as needed. This provides the DSO flexibility in operating their grid as they like with minimal autonomous control from the DER controller. On the other hand, the disadvantage is its limited deployment, where the system is designed for a specific group of DER sites with forecasted production patterns. Project developers may face significant hurdles when attempting to scale the project beyond the specifics.

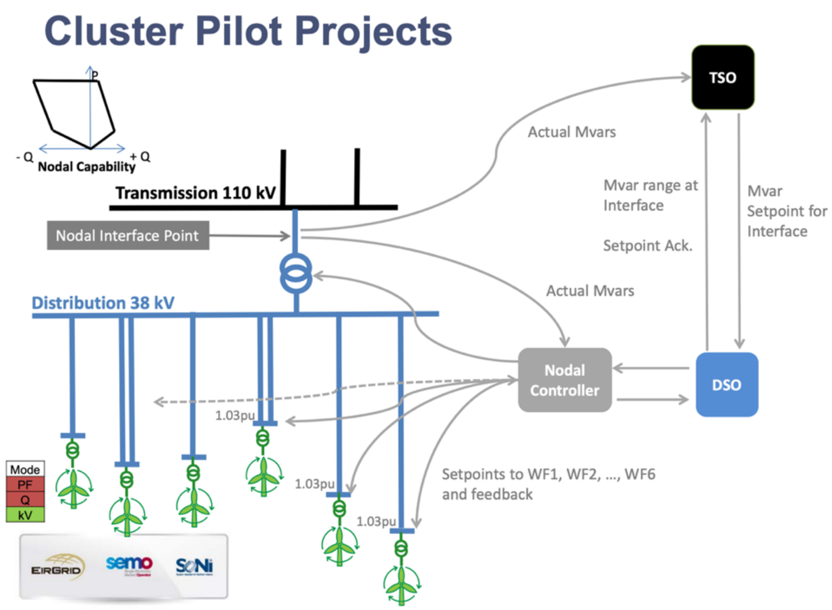

Figure 31: EIRGRID Nodal Controllers project schematic diagram

National Grid's Power Potential: Power Potential is an ambitious attempt to provide full TSO-DSO interaction through the interchange of reactive power. Power Potential's first goals are to reduce constraints and power quality issues on the transmission system by absorbing reactive power in the distribution system's DER. They do this by proposing the creation of a reactive power market where economic value is attached to reactive power through its supply and demand relationship between the various participants in the market [40].

The project is a yet-to-be-deployed pilot program that focuses on four substations in the southeast region on the United Kingdom, as seen in figure 32, and introduces a new DERMS control mechanism to control DER on those four substations according to the transmission's system operator's needs upstream, as seen in figure 33.

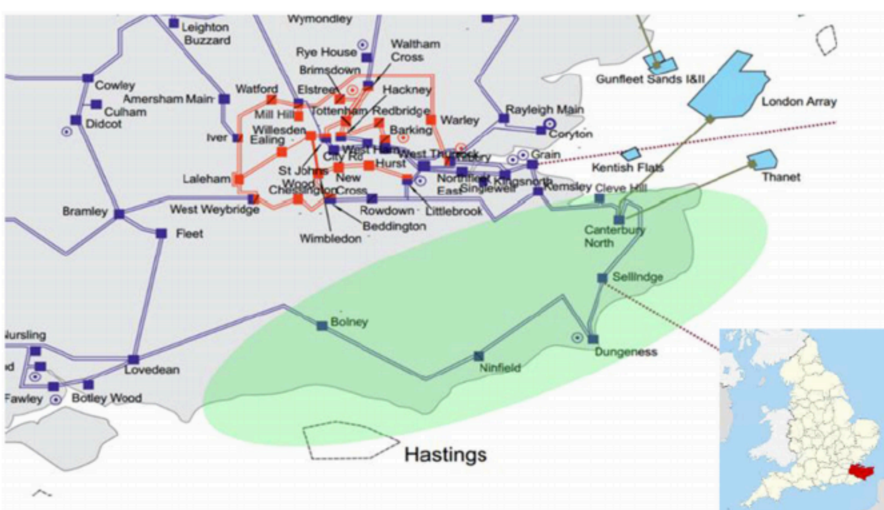

Figure 32: National Grid Power Potential project geographic location

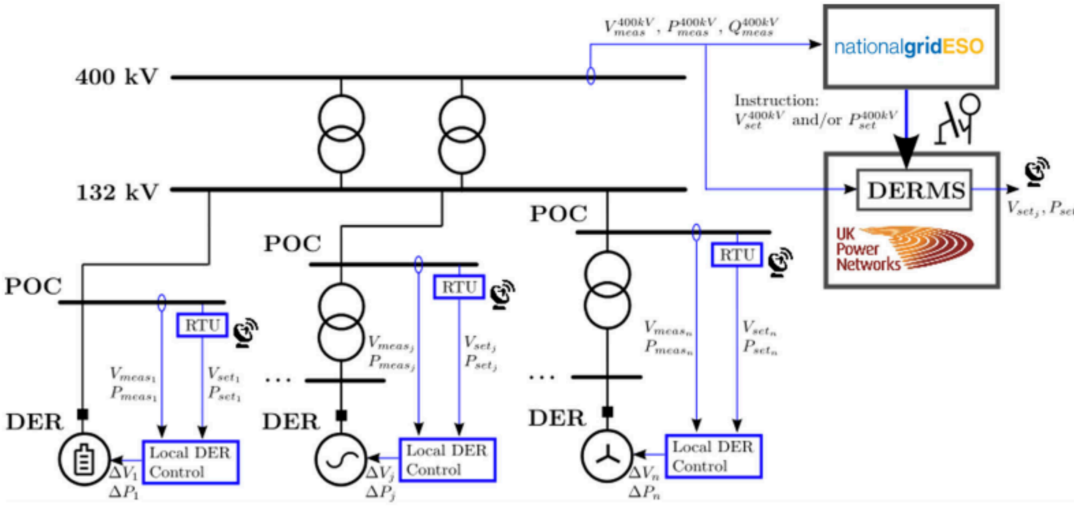

Figure 33: National Grid Power Potential project schematic diagram

Power Potential, while overly-ambitious for a first-time development, can be a critical litmus test for the real-world implementation of TSO-DSO interaction through reactive power exchange. Its success or failure can be a guiding path for utilities around the world that are facing the same challenges National Grid is facing in the UK or Atlantic Electric in Massachusetts. Nevertheless, it is important to reiterate that Power Potential's scope is fairly large, which can be a distraction when trying to solve one challenge at a time.

5.3. Final Conclusions and Summary of Contribution

The goal of this project is to define the value proposition of using DG smart inverters as a solution to reduce transmission-level over-voltage caused by increased DG penetration. This was done through the study of two representative feeders (and their associated substations) in the Central/Western Massachusetts area. The study included feeder-level electrical load flow analysis for a variety of system conditions using a newly defined modeling methodology. The study also included the development of a cost-benefit analysis investigation on the two representative feeders comparing them against the traditional solution the utility would have implemented.

Any conclusions derived from this work are specific to the conditions discussed and come with many limitations before they can be generalized more broadly. This study solely focuses on the transmission infrastructure in the ISO-NE region of Massachusetts. This study only looked into two distribution feeders and their associated substations within the area of interest. This study assumes that the only base case for a cost-benefit analysis is the installation of shunt reactors on the transmission system. This study briefly mentions but chiefly disregards any regulatory or commercial challenges that may arise from implementing the proposed solution – rather, it solely focuses on the technical challenge.

Finally, the contribution of this work is summarized as:

- The design and specification of an implementable system that can reduce overvoltage on the transmission system through DG inverters on the distribution system
- The definition of maximum reactive power absorption limits of two of Atlantic Electric's distribution feeders – what we call: Reactive Power Hosting Capacity
- The definition of the attainable cost savings from implementing the inverter solution.

5.4. Future Work

There are many approaches that can be made to improve upon this work. I divide them here into two main categories: research-based future work and implementation-based future work.

1. Research-based future work:
    - Studying additional feeders with a larger diversity of characteristics
    - Studying how control architecture can be integrated into a larger DERMS system
    - Studying the effects of the proposed system on VVO controls on a distribution feeder
    - Studying the aggregate effect of nodal transmission voltage reduction on a transmission line or network

2. Implementation-based future work:
    - Developing a pilot project that demonstrates in real life how absorption targets can be set and how the voltage on the transmission system can be affected
    - Redesigning the interconnection standards in Massachusetts to require smart inverter installations on all DG sites
    - Developing a compensation structure for reactive power in Massachusetts electricity markets

Glossary

AC	Alternating Current
ADMS	Advanced Distribution Management Solutions
AI	Advanced Inverters
ANSI	American National Standards Institute
CBA	Cost-Benefit Assessment/Analysis
CPUC	California Public Utilities Commission
CVR	Conservation Voltage Reduction
CYME	CYME Power Engineering Software
DC	Direct Current
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DOER	Department of Energy Resources, Massachusetts
DPU	Department of Public Utilities, Massachusetts
DTT	Direct Transfer Trip
DVAR	Dynamic VAR Control
EPRI	Electric Power Research Institute
EPS	Electrical Power System
GCA	Green Communities Act, Massachusetts
IEEE	Institute of Electrical and Electronics Engineers
ISO-NE	Independent System Operator of New England
NDA	Non-Disclosure Agreement
NREL	National Renewable Energy Laboratory
PCC	Point of Common Coupling
pf	Power Factor
POI	Point of Interconnection
PPA	Power Purchase Agreement
PV	Photovoltaic
RTAC	Real-Time Automation Controller
SCADA	Supervisory Control and Data Acquisition
SI	International System of Units
SMART	Solar Massachusetts Renewable Target
UL	UL LLC - global safety certification company
VVO	Volt-VAR Optimization
[M/k]VA	Volt Amperes – unit for measure of apparent power
[M/k]VAR	Volt Amperes Reactive – unit for measure of reactive power
[M/k]W	Watt – unit for measure of real power

Bibliography

[1] E. Taibi *et al.*, *Power System Flexibility for the Energy Transition*. 2018.

[2] “Session Law - Acts of 2008, Chapter 169.” https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169 (accessed Apr. 04, 2020).

[3] “Solar Massachusetts Renewable Target (SMART) Program,” *Mass.gov*. https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program (accessed Apr. 04, 2020).

[4] “MassDGIC: Interconnection in Massachusetts - Distributed Generation and Interconnection in Massachusetts.” https://sites.google.com/site/massdgic/home/interconnection (accessed Apr. 04, 2020).

[5] “The Growth of Distributed Generation: ISO New England’s Role in the Interconnection Review Process.” ISO New England, Oct. 2019, [Online]. Available: https://www.iso-ne.com/static-assets/documents/2019/10/iso_new_england_interconnection_review_process_information_resource_october_2019_final.pdf.

[6] M. Rylander, J. Smith, and W. Sunderman, “Streamlined Method for Determining Distribution System Hosting Capacity,” in *2015 IEEE Rural Electric Power Conference*, Asheville, NC, USA, Apr. 2015, pp. 3–9, doi: 10.1109/REPC.2015.11.

[7] “Photovoltaic Plant Output Variability and Grid Voltage,” p. 17, 2018.

[8] W. Kersting, “Distribution Feeder Voltage Regulation Control,” *Ind. Appl. IEEE Trans. On*, vol. 46, pp. 620–626, May 2010, doi: 10.1109/TIA.2010.2040060.

[9] A. Hoke, “Inverter Anti-Islanding with,” p. 41.

[10] G. Deb, “Ferranti Effect in Transmission Line,” vol. 2, no. 4, p. 6, 2012.

[11] “ISO New England - Energy, Load, and Demand Reports.” https://www.iso-ne.com/isoexpress/web/reports/load-and-demand (accessed Apr. 04, 2020).

[12] “Boston, MA Weather History | Weather Underground.” https://www.wunderground.com/history/daily/KBOS/date/2019-5-10 (accessed Apr. 04, 2020).

[13] “FlexibleResourcesHelpRenewables_FastFacts.pdf.” CAISO, Accessed: Apr. 04, 2020. [Online]. Available: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

[14] “ISO Newswire - Updates - Quack! Quack! New England sees back-to-back afternoon demand lows.” http://isonewswire.com/updates/2020/2/25/quack-quack-new-england-sees-back-to-back-afternoon-demand-l.html (accessed Apr. 18, 2020).

[15] “Common Functions for Smart Inverters: 4th Edition,” *EPRI*, no. 4th edition, p. 170, Dec. 2016, [Online]. Available: https://www.epri.com/#/pages/product/3002008217/.

[16] J. L. Kirtley, *Electric Power Principles: Sources, Conversion, Distribution and Use*. John Wiley & Sons © 2010.

[17] “IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces,” IEEE. doi: 10.1109/IEEESTD.2018.8332112.

[18] T. Basso, “IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid,” NREL/TP-5D00-63157, 1166677, Dec. 2014. doi: 10.2172/1166677.
[19] “Smart Inverter Working Group.” https://www.cpuc.ca.gov/General.aspx?id=4154 (accessed Apr. 04, 2020).
[20] J. Berdner, “Summary of CA Rule 21, Phase 3.”
[21] J. Bobruk, “Are You Ready For Rule 21?,” p. 35.
[22] “Advanced Inverter Interconnection Requirements for Inverter-Based Distributed Energy Resources.” Hawaiian Electric Company, Nov. 2015.
[23] “UL - 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources | Standards Catalog.” https://standardscatalog.ul.com/standards/en/standard_1741_2 (accessed Apr. 04, 2020).
[24] J. Smith, “Grid Impacts of Distributed Generation with Advanced Inverter Functions: Hosting Capacity of Large-Scale Solar Photovoltaic Using Smart Inverters,” p. 62.
[25] “Recommended Smart Inverter Settings for Grid Support and Test Plan: Interim Report,” p. 16, 2018.
[26] Rogers, “Smart Grid Ready PV Inverters with Utility Communication: Results from Field Demonstrations,” p. 196.
[27] C. Schauder, “Advanced Inverter Technology for High Penetration Levels of PV Generation in Distribution Systems,” NREL/SR-5D00-60737, 1129274, Mar. 2014. doi: 10.2172/1129274.
[28] S. R. Abate, T. E. McDermott, M. Rylander, and J. Smith, “Smart inverter settings for improving distribution feeder performance,” in *2015 IEEE Power & Energy Society General Meeting*, Denver, CO, USA, Jul. 2015, pp. 1–5, doi: 10.1109/PESGM.2015.7286560.
[29] G. Kern, “Volt Watt Function with Ppre Mode Will Unfairly Favor Systems That Generate Power Earlier in the Day,” p. 9.
[30] A. Hoke, “Frequency-Watt Control: Customer Impacts and Recommended Settings,” p. 6.
[31] G. Kern, “Volt-Var, Volt-Watt, Reactive Power Priority Model,” p. 23.
[32] S. Electric, “Advanced Distribution Management Systems: The Foundation of Distribution System Operations,” p. 6.
[33] “Schneider - Digital_grid_unleashed_eBook_998-20256456_GMA-US.pdf.” .
[34] “SEL-3555 Real-Time Automation Controller (RTAC),” *selinc.com*. https://selinc.com/products/3555/ (accessed Apr. 04, 2020).
[35] “Load Costs.” https://www.iso-ne.com/markets-operations/market-performance/load-costs/ (accessed Apr. 05, 2020).
[36] “S&P Global Market Intelligence; [Renewable Energy Credits].” .
[37] G. Migliavacca, Ed., *TSO-DSO Interactions and Ancillary Services in Electricity Transmission and Distribution Networks: Modeling, Analysis and Case-Studies*. Springer International Publishing, 2020.
[38] Z. Li, *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. Springer, 2018.

[39] "ISGAN - Needs, challenges and opportunities of TSO-DSO coordination." http://www.iea-isgan.org/needs-challenges-and-opportunities-of-tso-dso-coordination/ (accessed Apr. 04, 2020).
[40] "Power Potential | National Grid ESO." https://www.nationalgrideso.com/innovation/projects/power-potential (accessed Apr. 04, 2020).