Impact of Advanced Vol-VAr Control Devices on Increasing PV Hosting Capacity of Distribution Systems

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***Abstract*— Adoption of renewable energies is on the rise all over the globe. Among renewable energy resources, solar Photovoltaic (PV) resources have gained a significant momentum in multiple parts of the world. Beside all the benefits renewable energy resources provide, they have also introduced new challenges, which must be addressed as soon as possible. This paper focuses on the mitigation of voltage issues caused by high penetration of PV resources. In this work, new Volt-VAr Control (VVC) devices such as smart inverters and Dynamic VAr Controllers (DVCs) are selected and the interplay between them is investigated. Furthermore, the impact of these new VVC technologies on reducing voltage volatility and consequently increasing PV hosting capacity of distribution systems is assessed. To achieve those objectives, advanced Quasi-Static Time-Series (QSTS) simulations are performed in OpenDSS and controlled by Python. These powerful tools provide the opportunity to model new VVC devices, to implement advanced VVC schemes and smart functions, and to investigate the interaction between new VVC devices. Simulation results for select feeders show that by employing smart inverters and DVCs, existing PV hosting capacity of the considered Hawaiian distribution system can increase by 15% and 45% respectively compared to existing installed capacity. However, when both technologies are utilized, PV hosting increases by 60% for the select feeders, indicating that DVCs complement smart inverters capabilities.**

***Index Terms*—Dynamic VAr Controllers, Photovoltaic, Smart Inverters, Solar Energy, Volt-VAr Control**

I. INTRODUCTION

Climate change impacts have been noticed and felt by many nations. As a response, a significant shift toward renewable energy resources has been observed all over the globe. Renewable energy resources are the cornerstone of tackling climate change and reducing CO2 emissions. Enormous growing installed capacity of renewable energy resources in the United States, Australia, China, Germany, and Denmark are the bright examples of this drastic shift [1]. Considering the US specifically, some states are reaching for 50%-100% renewable portfolios in the next 10-20 years, such as California and New York with a target of reaching 60% and 50% by 2030 respectively [2], and the state of Hawaii with a target of reaching 100% renewable portfolio by 2045 [2].

A significant part of growing renewable generation is solar Photovoltaic (PV) in its various forms: utility-owned, commercial and residential roof-top PV. Just in 2017, the world added more solar capacity than any other form of power generation technology [1]. Beside all the benefits solar energy provides, it comes with some challenges. The main challenge to overcome is the intermittent nature of solar energy. The output of solar resources can drop from 100% to 20% in matter of seconds due to cloud shadows and then go back to the previous level. This pattern repeats multiple times during a cloudy day [3].

These irradiance fluctuations and consequently variations in PV generation can cause adverse impacts on power systems such as under/over voltage violations, reverse power flow, voltage fluctuations and flicker [4]. High voltage fluctuations lead to voltage flicker and degrades power quality of consumers. Reverse power flow causes over-voltages originating on the secondary side (208V-277V) of distribution service transformers. Over-voltages tend to pose safety concerns for utility crew members and can also damage consumer equipment. Therefore, the aforenoted issues must be addressed.

Till date, all utility solutions to manage grid voltage have existed on the primary side (4kV-25kV). Primary Volt-VAr Control (VVC) assets such as switched capacitors and Load Tap Changers (LTC) cannot effectively mitigate the voltage issues due their slow-acting nature originating from their delays (usually1-2 minutes).

Several studies have addressed the issues associated with solar PV resources deployed in distribution systems. Common solutions have been around smart inverters [5], and energy storage systems [3]. New technologies such Dynamic VAr Controllers (DVCs) can also provide a promising avenue under utilities belt to mitigate voltage issue [6], [7] in a distributed manner.

In this paper the interaction between smart inverters and DVCs, the new technologies that are going to be adopted by utilities for managing solar PV induced issues, is investigated. This paper also aims to evaluate the impact of these new technologies to decrease voltage volatility and to increase PV hosting capacity of distribution systems. It is expected to observe an increase in PV hosting capacity of distribution systems employing these technologies. However, the more important question to be answered is the contribution of each technology and their combined impact.

To achieve the aforementioned objectives, advanced Quasi-Static Time-Series (QSTS) simulations with one-minute time-steps are performed in OpenDSS and controlled by Python through COM interface. Volt-VAr control of smart inverters and fast and effective voltage control of DVCs are modeled using OpenDSS features. Furthermore, different load and PV generation scenarios as well as various controls scenarios are investigated to provide a comprehensive analysis.

Rest of the paper is organized as follows. Section II discusses smart inverter and DVC voltage control strategies plus their advantages and disadvantages. In section III, the case-study is presented and model conversion from Synergi Electric to OpenDSS as well as its validation is discussed. Section IV presents the PV hosting simulation analysis results for various control strategies. Finally, section V concludes the paper with some remarks.

II. Advanced Volt-VAr Control Devices

A. *Smart Inverters*

With increasing penetration of solar PV resources, voltage issues have risen. As a response to those voltage issues, different strategies of controlling real and reactive powers have been proposed and utilized through employing smart or advanced inverter functions. IEEE 1547, California Rule 21 and Hawaii Rule 14H have accelerated the integration of smart inverters. Volt-VAr Control (VVC), and Volt-Watt Control (VWC) which control reactive and real powers respectively are examples of the strategies to alleviate the voltage issues caused by solar PV resources. Fig. 1 shows the characteristics of Volt-VAr control [8]. As illustrated in the figure, encountering low voltages (voltages lower than V2), reactive power will be injected. On the other hand, when high voltages occur (voltage higher than V3), reactive power will be absorbed to mitigate high voltages.

VVC and VWC curves are typically set to allow VVC to operate first to allow an inverter's reactive capabilities to

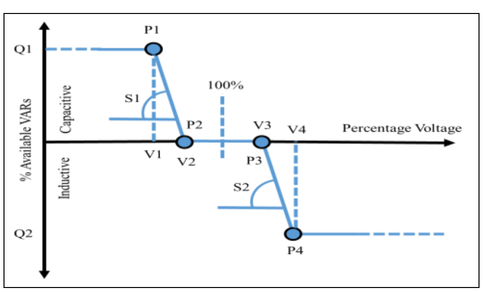

Figure 1. VV control strategy characteristics [8]

respond to voltage excursions. VWC curve is typically set to activate if voltage exceeds utility tariff limits. With VWC, curtailment of real power will occur after reaching a specific voltage.

An interesting, but often overlooked, point to consider is that smart inverters may not have the adequate reactive power support to control voltage to the degree required while operating under VVC. The maximum reactive power support, either injection or absorption, is limited to 44% of the rated capacity per Hawaii Rule 14H and default settings of IEEE 1547 category B (high PV penetration) and 30% in California Rule 21. Considering the Hawaii Rule 14H as an example, reactive power is limited to 44% of the rated PV capacity beyond 127.2V (1.06*120V). If an inverter capacity is assumed to be 5 kVA, 44% of the rated capacity is 2.2 kVAr. Considering the corresponding slope (S2), at 126V (Upper ANSI-A limit) the inverter will absorb only 1.5 kVAr, which may not be sufficient to bring the voltage back within the ANSI range.

Another item to point out is the fact that smart inverters may not be deployed where mitigation is required as utilities do not control where the next residential PV generation will be deployed. Last but not least, smart inverters may not be owned by utilities. Therefore, their participation in voltage control depends on the owner's choice. This raises another concern for utilities, which have historically exercised deterministic and reliable control over their systems.

B. *Dynamic VAr Controllers (DVC)*

Smart inverters with autonomous functionality may help to mitigate some of the voltage issues associated with high penetration of solar PV resources. However, they alone cannot mitigate the impact of legacy inverters. Hence, other solutions are needed to mitigate voltage issues and to maximize PV hosting capacity of distribution systems. DVC is a promising technology to achieve those objectives. DVCs are utility-owned devices, which regulate the voltage effectively on the secondary side of service transformers. Adequate number of DVCs also can mitigate the voltage drop on the primary side and can replace or alleviate the need for primary capacitors by providing reactive power support. DVCs are shunt connected devices, generally single-phase but can be designed to be three-phase operating on the secondary side voltages. DVCs can regulate voltage tightly by injecting reactive power when the sensed voltage drops below a configurable set-point and by reducing reactive power injection when the voltage rises above the set-point. These dynamic and fast-acting devices can inject reactive power in the increments of 1 kVAr and up to 10 kVAr on a sub cycle basis [6].

The collective action of DVCs helps control grid voltage and therefore unlocks a simple grid-edge VVO/CVR scheme that provides energy saving and peak demand reduction. DVCs achieve those objectives by attacking low voltages locally and reducing voltage volatility of distribution systems. As a result, Load-Tap-Changer (LTC) or Feeder Head-Regulator (FHRs) set-points can be reduced without encountering under-voltages and due to voltage dependency of loads, demand reduction and consequently energy saving can be achieved. Tapping down LTCs or FHRs also provides an extra upper voltage headroom which prevent over-voltages induced by installing new solar PV resources and increases PV hosting capacity of distribution systems.

Although the DVC technology has several advantages over conventional VVC devices, it has its own limitations. Even though DVCs can be designed to absorb reactive power for directly reducing voltage, generally it is more expensive to do so, hence most cost-effective DVC solutions can only inject reactive power. Secondly, DVCs are dependent on system impedance such as service transformer and upstream line impedance values to have an impact on voltage support. Finally, even though DVCs have been shown to provide 1% - 3% feeder-wide voltage improvement [9], being a shunt connected technology the provided voltage control is system dependent. Nevertheless, cost-benefit analysis has shown that the advantages of DVC technology far outplay its limitations.

III. Case Study and Model Conversion

The case study in paper is a Hawaii substation with three feeders located in the island of O'ahu. An LTC is controlling the voltage at the substation. There are also two single-phase voltage regulators, one on phase B and one on phase A of one of the feeders. The LTC is operating in Line Drop Compensation (LDC) mode. Peak load is 3.58 MW and existing installed PV capacity is 2.56 MW. Hence, PV penetration with respect to peak load is 71.5%. The maximum distance from the substations is 4.6 miles. There are also 17 DVC units on two of the feeders.

In order to assess the impact of DVCs and smart inverters on increasing PV hosting capacity by mitigating voltage issues, a major effort was devoted towards performing Quasi-Static Time-Series (QSTS) analysis in OpenDSS. In the following, model conversation, model validation, secondary circuit models and the employed load and PV profiles are discussed.

A. Model Conversion

The first step was to create a Synergi-to-OpenDSS (Syn2DSS) converter that was developed using MATLAB™. The result of the conversion is shown in Fig. 2 validating the topological correctness of newly minted OpenDSS model.

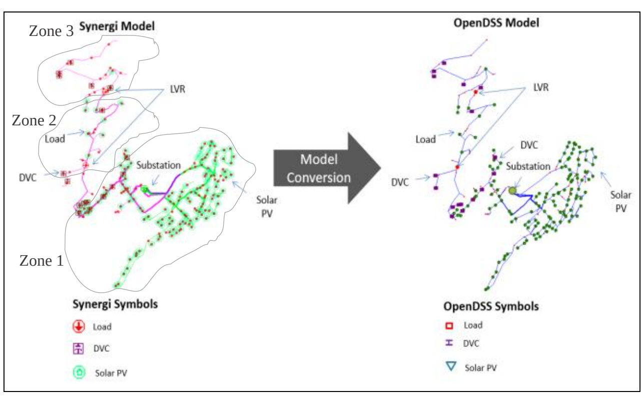

Figure 2. Synergi Electric model converted to OpenDSS model

B. Validation

The next step was to validate the primary circuit model that is converted to OpenDSS from Synergi Electric. Only primary voltages were compared. Several parameters were monitored during the validation process including, power flow and voltages at the substation as well as the power flow and primary voltages at every individual node in the system. Fig. 3 shows that the conversion accuracy was as high as 99.64% for all transformer primary voltages in the system.

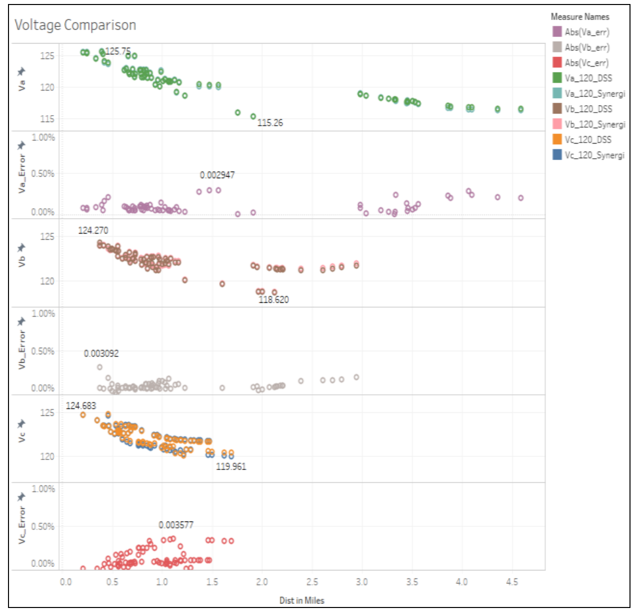

Figure 3. Service transformer voltage comparison between OpenDSS and Synergi Electric models

C. Secondary Models and circuits

As the Synergi model of the case study does not include the information on secondary conductors, a significant step of adding secondary conductors to the model was included to the modeling process. A simple method would be to use a single line that models a secondary conductor after the service transformer. However, this method does not capture the complexity inherent to secondary networks. In fact, having a close to accurate secondary network model is essential in understanding the voltage rise/drop caused due to load/PV generation.

In an effort to closely model the secondary network, a Binary Branch Model (BBM) of the secondary was developed that considered the number of customers connected to the transformer from Synergi Electric, and the impedance of secondary conductor based on ampacity values. Using some real secondary network designs, the model was tuned, and a script was developed to add the BBM for every transformer in the model. As the studied substation did not have AMI data to compare the voltage on secondary network, an example model was developed that compared an actual circuit with 12 customers connected to the secondary of the transformer with the BBM. The results of this comparative simulation are shown in Fig. 4. From the simulation, it is evident that the BBM very closely captures the minimum and maximum voltage at the customers albeit it loses the resolution of voltage at every single customer location. As the emphasis of the simulation is to capture the minimum and maximum voltage, the loss of resolution is not considered a major drawback.

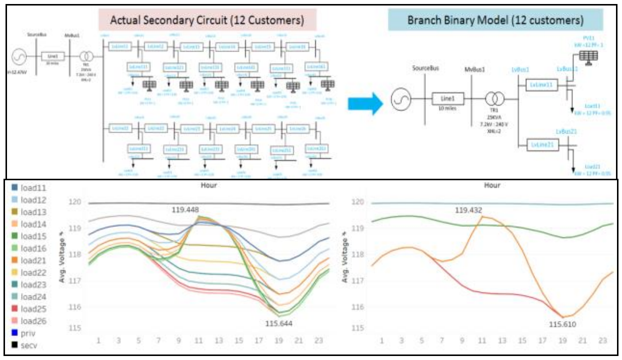

Figure 4. Comparison of Binary Branch Model with the actual model using OpenDSS simulation

D. *Load and PV Profiles*

For running all the simulations, extreme load and PV profiles were considered that captured all possible variations in the actual system. The native load was extracted from the load flow at the substation and PV irradiance measurements for that specific day. Two different native load combinations with minimum and maximum loads were considered and combined with PV irradiance representing a sunny, cloudy, and overcast days. This provided a total of six different combinations of load-PV profiles (low load, high load, sunny, cloudy, overcast) as shown in Fig. 5. During the cloudy day, PV irradiance is fluctuating multiple times between 20-40 %, which helps to probe effectiveness of VVC devices to mitigate voltage issues under challenging situations.

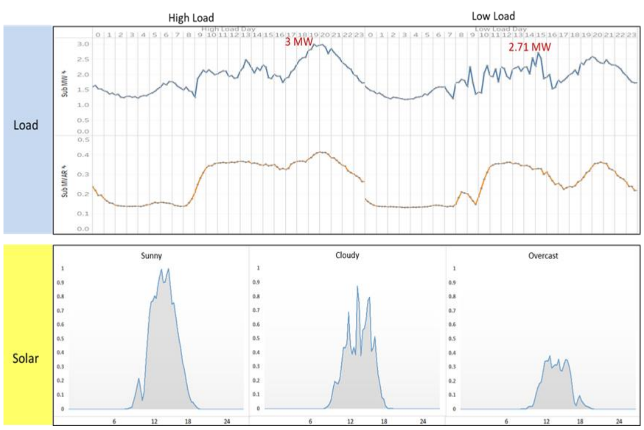

Figure 5. Load and PV profiles considered for all simulation scenarios

IV. Simulation Results

A. *PV hosting Siumation Resutls*

To compute PV hosting capacity, ANSI range A is selected as the criterion. The analysis is started with the existing PV penetration level. Gradually PV penetration is increased through random installation of PV systems and when voltage volatility reaches 12 V (10% of 120V) that PV penetration is considered as the PV hosting capacity. In the process of randomly adding PV systems, the ratio of rated PV capacity (existing and added PV) should not be more than 300% of maximum load in any load locations. Note that the analysis is not limited by minimum voltage or maximum voltage, but with the voltage volatility, which is maximum voltage minus minimum voltage of the all the load-PV scenarios. Because it is assumed that as long as the 12V limit is not reached, by changing the LTC set-point over-voltages (over 126 V) and under-voltage (under 114 V) can be mitigated.

As mentioned, the substation has one LTC and two voltage regulators on one of the feeders. Hence, creating three voltage zones illustrated in Fig 2. To compute voltage volatility, maximum and minimum load voltages of all the six load-PV scenarios are found though performing QSTS simulations. Then maximum of the maximum voltages and minimum of the minimum voltages of all load-PV scenarios are selected and the difference, which is voltage volatility, is computed for each voltage zone (three values). The maximum value of the three zone voltage volatility values is the system voltage volatility, which is used to determine the PV hosting capacity.

Furthermore, to compute the maximum possible PV hosting capacity for the studied substation, five different control scenarios were simulated. These scenarios are explained below:

• LegacyPV: All inverters are legacy Inverters

• LegPV+SmartPV: New PV installation are smart inverters

• LegPV2SmartPV: All legacy inverters are converted to smart inverters

• LegPV+DVC: Only DVCs present in the system with legacy inverters

• LegPV+SmartPV+DVC: New PV installations are smart inverters and DVCs are added to the system to complement smart inverters

For all these cases, the smart inverter settings were chosen to be that recommended in Hawaii Rule 14H (6% dead-band). The results of these simulations are provided in Fig. 7.

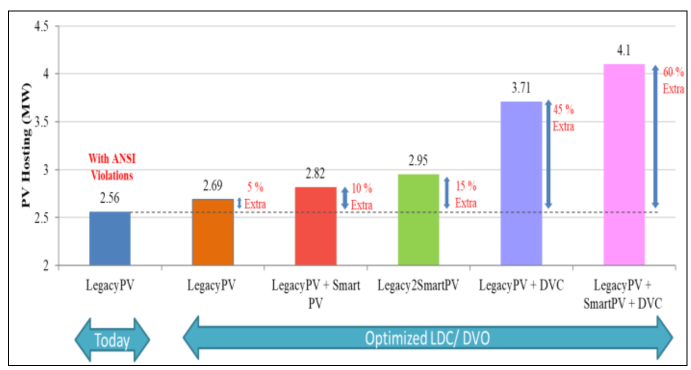

Figure 6. PV hosting capacity simulation results under different scenarios

Key items to point out are:

• Current system (only legacy inverters) suffers from ANSI range A voltage violations.

• Smart inverters (no retrofits) alone provide extra 10% PV hosting capacity (based on currently installed capacity) if and only if optimized settings are used.

• All legacy inverters retrofitted with smart inverters and all new PV installations being smart inverters provide 15% extra PV Hosting capacity with optimized LDC and LVRs settings.

• DVCs alone provides 45% extra PV hosting capacity with optimized settings. However, even with current LDC/LVRs settings, DVC can eliminate all ANSI voltage violation for base case PV penetration.

• DVCs and smart inverters (no retrofits) provide 60% extra PV hosting capacity.

B. Interplay between Smart Inverters and DVCs

To better understand the interplay between smart inverters and DVCs, 6-sec QSTS simulations are performed with higher resolution of load and PV irradiance profiles. Reactive power contribution of smart inverters under VVC and DVC are then analyzed for specific PV penetration scenarios. Figures 7 and 8 show reactive power contribution of smart inverter and DVCs for two control strategy scenarios.

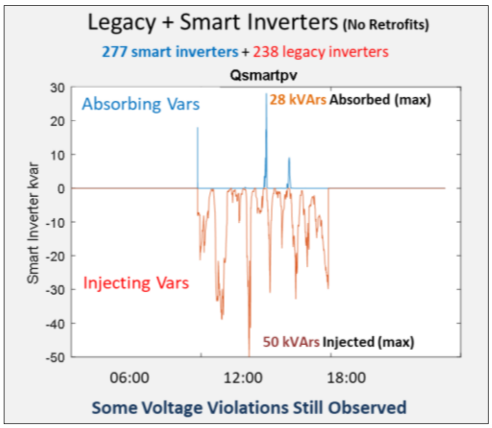

Figure 7. Reactive power contribution of smart inverter

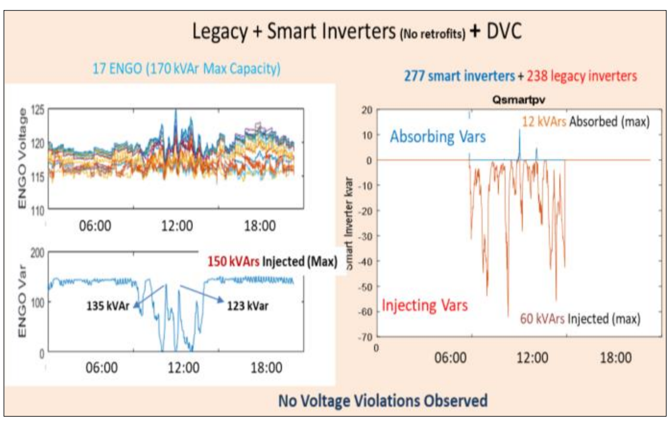

Figure 8. Reactive power contribution of smart inverter and DVCs

Fig 7 shows reactive power absorption/injection of smart inverters when total PV size is 4.1 MW and only smart inverters are performing VVC. As seen maximum absorption of 277 smart inverters is 28 kVAr (sum of all absorptions) and maximum injection of all smart inverters is 50 kVAr. Those values are not sufficient for mitigating all voltage problems and voltage violations are observed. On the other hand, Fig 8 illustrates the reactive power contribution of DVCs and smart inverters for the same PV penetration level when both technologies are employed. The figure in the middle shows that DVCs reacting dynamically (0-150 kVAr) to the voltage variations and this leads to mitigating all voltage issues.

V. Conclusions

With increasing penetration of solar PV resources, and the intermittent nature of solar energy, voltage issues associated with solar PV resources are introducing new challenges to system operators and planners. This paper investigated how new technologies such as DVCs and smart inverters interact and how they can address those challenges. It also probed the contribution of these technologies to increase PV hosting capacity of select Hawaii distribution circuits. In this work, six load-PV scenarios and five control strategies were considered to perform a comprehensive analysis to consider extremes situations that may occur throughout a year as well different control strategies that may be utilized.

The simulations results showed that converting all the legacy inverters to smart inverters, a total of 515 smart inverters, which employ volt-var control could increase the PV penetration by 15% and could mitigate all voltage issues that today exist. Using only 17 DVC devices, the PV hosting capacity increased by 45% compared to the existing solar PV install capacity. In this case, all inverters are legacy inverters. Finally, combining smart inverters and DVCs, two technologies that show promise for utilities grappling with high PV penetration in their distribution networks, the PV hosting capacity of the select circuits increased by 60%.

This study illustrated that DVCs that tightly regulate grid voltage and are utility owned assets are tuned to provide optimal reactive power in response to local conditions. Therefore, DVCs can complement the capabilities of smart inverters to solve the voltage issues observed on the grid while fully owned and controlled by power distribution utilities. Considering the shown combined impact of smart inverters and DVCs to resolve voltage issues, it seems a golden era of renewable energy resources has arrived.

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