21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2022 Grid of the Future Symposium

Evaluation of Smart Inverter Volt-Var Control Stability on a National Grid Distribution Feeder

W. WANG[1], A. HUQUE[1], W. REN[1], D. VAN ZANDT[1], J. VAZ[2], S. ARAFA[2], R. KANKANAMALAGE[2]
[1]Electric Power Research Institute, [2]National Grid USA Service Company

SUMMARY

Smart inverter grid support functions, such as volt-var and volt-watt controls required in IEEE Std 1547™-2018, have the potential to alleviate over-voltage and voltage variation issues caused by high penetration of distributed energy resources (DERs), especially solar photovoltaics (PV), on the distribution circuit. However, because of the dynamic nature of volt-var and volt-watt control functions, distribution engineers have raised concerns about potential voltage oscillation caused by the interaction of these controls with the distribution system, with each other, and with other existing voltage regulating equipment on the circuit.

While previous research has investigated and revealed potential volt-var and volt-watt control instability for DERs interconnected at weak system locations and with aggressive control settings, often the DERs were analyzed individually ignoring the potential adverse control interaction among them. Moreover, such studies were mainly based on fictitious feeder model and/or DER size and locations.

This paper extends the previous research by investigating the stability of volt-var control function on a real National Grid (NG) feeder with 11 PV sites. Through dynamic simulation studies, the risk of instability when part or all of the PV sites activate volt-var control functions is analyzed with different control settings. Furthermore, potential control interaction among multiple PV sites with volt-var control is investigated considering non-uniform control settings.

KEYWORDS

Control interaction, smart inverter, stability, voltage oscillation, volt-var

wwang@epri.com

1. Introduction

Deployment of inverter-based DERs such as PV and energy storage (ES) in the distribution system is increasing rapidly. The addition of many DERs presents new challenges for distribution service providers in the form of changes in load shape, potential voltage violations, and reliability issues. One method to mitigate challenges to grid integration of proliferating DERs is effective utilization of smart inverters, which offer advanced grid-support capabilities like active and reactive power management to support voltage and frequency regulation, fault ride-through, and communication interoperability.

To address the potential voltage violation issues, IEEE Std 1547™-2018 requires DERs, such as PV inverter-interfaced generation, to be capable of several voltage control functions (such as volt-var and volt-watt controls). Even though DER volt-var and volt-watt control functions have been proven effective in mitigating voltage issues and have been used by some distribution utilities [1], there is still relatively limited field experience with these types of advanced active and reactive power control functions on distribution systems. As a result, distribution engineers have raised concerns about potential voltage oscillation caused by the interaction of these controls with the distribution system, with each other, and with other existing voltage regulating equipment on the circuit.

Previous research conducted by Electric Power Research Institute (EPRI) has investigated the potential volage oscillation caused by volt-var or volt-watt control function [2]-[6]. It has been shown by lab testing, analytical analysis and simulation studies that while the default settings in IEEE Std 1547™-2018 typically ensures control stability, aggressive volt-var or volt-watt control settings can result in unstable voltage oscillations when the DER is connected to a weak system location. Other research efforts also revealed the instability risk of volt-var control in distribution systems [7]-[11]. However, in most of the previous research the DERs were analyzed individually ignoring the potential adverse control interaction among them. [3] includes analyses with multiple DERs but the feeder model considered is fictitious.

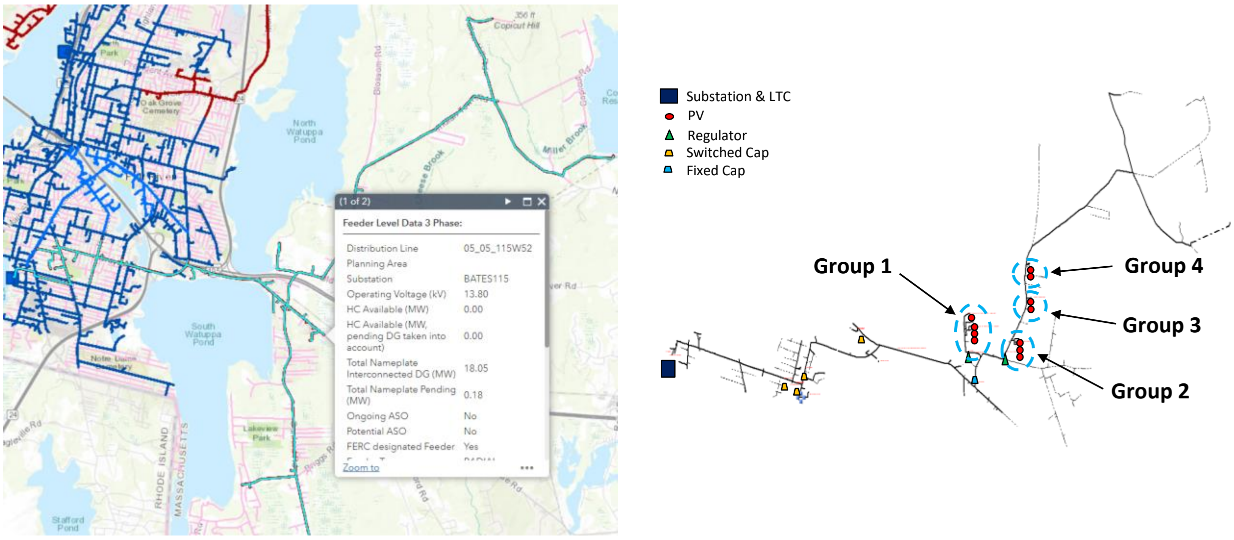
This paper presents results from a collaborative multi-year research project between EPRI and NG, which aims to investigate and demonstrate potential benefits as well as operational concerns of smart inverters in real-life PV plants connected to NG's distribution system. In particular, results presented in this paper shed light on the voltage oscillation risk due to aggressive volt-var settings from multiple DERs on a distribution feeder. It extends the previous research by considering volt-var control interaction among multiple DERs on a real distribution feeder. Moreover, a simple and efficient modeling and simulation approach to analyze volt-var control stability is presented in this paper, which leverages Python and CYME, and does not require detailed electromagnetic (EMT) modeling of the DERs.

The remainder of the paper is organized as follows: section 2 provides an overview of the NG feeder studied. The DER modeling and simulation approach to analyze volt-var stability is presented in section 3, which also provides some background on volt-var control defined in IEEE Std 1547™-2018. Next, section 4 presents the dynamic simulation results which evaluate the risk of volt-var control instability and the potential interaction among multiple DERs. An introduction on the volt-var control stability mechanism and the key impacting factors is also included in section 4 to facilitate understanding. Finally, section 5 concludes the paper.

2. Description of the NG Feeder Studied

As shown in Fig. 1 (a) [12], the NG feeder under study is a 13.8 kV distribution feeder located in the city of Fall River, MA. The feeder has 11 PV sites (shown by the red circles in Fig. 1 (b)) interconnected at different locations. The active power ratings of the PV sites range from 1 MW to 1.75 MW. For the scenario considered, the total generation from the PV sites is around 14 MW while the total load in the system is around 8.2 MW.

Both uniform and different volt-var control settings at the various PV sites have been considered to analyze the instability risk and control interaction. For simplicity of the study, the PV sites are grouped into 4 groups based on proximity as illustrated in Fig. 1 (b). Moreover, for the PV sites inside each group, since they are close-by, the value of utilizing different volt-var control settings are marginal. Therefore, it is assumed that they have the same volt-var control settings.



(a) Feeder topology on map **(b) Feeder model in CYME**

Fig.1. Topology of the NG feeder under study

3. Dynamic Modeling of Inverter-based DER with Volt-Var Control

3.1 Introduction to Volt-Var Control Defined in IEEE Std 1547™-2018

IEEE Std 1547™-2018 requires a compliant DER to have volt-var control function available. The volt-var function controls the reactive power injected or absorbed by a DER in response to the measured voltage at the reference point of applicability (RPA). Ranges of volt-var parameters and default values are specified in Clause 5.3.3 of the standard. Although required to be available in the DER, activation of this function, and the control parameters used, are at the discretion of the utility (Area EPS Operator).

With the volt-var function activated, the amount and direction of reactive power is according to a curve defined by four points in the reactive power (Q) versus voltage (V) space, as illustrated in Fig. 2.

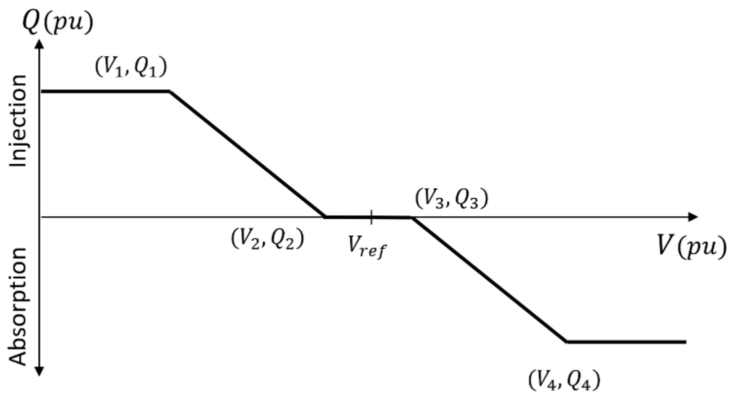


Fig.2. Illustration of volt-var control function defined in IEEE Std 1547™-2018

As can be seen, the curve may have a span of voltages for which the reactive power is zero, which is called a "deadband", and in this case, the reference voltage is the midpoint of this span. Settings without a deadband is also allowed, where $V_{ref} = V_2 = V_3$. There is flexibility in the ranges of parameters allowed in IEEE Std 1547™-2018 to create a volt-var curve different than that depicted in Fig.2. For example, the slopes for voltage greater than V_3 can be made different than for voltage less than V_2. While this flexibility is provided in IEEE Std 1547™-2018, these are atypical implementations of volt-var that will not be explored in this study.

Besides the volt-var curve settings, another important setting defined for volt-var control in IEEE Std 1547™-2018 is the open loop response time, which is the duration from a step change in control signal input (reference voltage or system voltage) until the output reactive power changes by 90% of its final change, before any overshoot. The open loop response time governs how fast the DER reactive power output changes following a change in the system voltage or its voltage reference setting. As revealed in [2] and [3], and also shown later in this paper, both the slope of the volt-var curve and the open loop response time settings affect volt-var control stability significantly.

3.2 Dynamic Modeling and Simulation Approach

In [2], detailed EMT models are developed for different inverters with volt-var control to match the lab testing results. Even though EMT models can represent detailed inverter control and hardware acurately, they are less efficient (i.e., more time consuming) for this study where an entire feeder and 11 PV sites are involved. Besides, based on EPRI's previous study, the volt-var control induced oscillation is mainly below 10 Hz, which can be captured using phasor domain models [3]. Therefore, three-phase phasor domain simulation is conducted for this study instead of EMT simulations.

The simulation is conducted by coupling Python with CYME as depicted in Fig.3. The NG feeder model including loads, capacitor banks and voltage regulators is modeled in CYME. Moreover, each of the 11 PV sites is represented as an electonically-coupled generator (ECG) in the CYME model where its active and reactive power output is controlled by the DER control model in Python.

The DER control functions including volt-var and constant power factor controls are modeld and simulated within a Python script, while CYME serves as a computation engine to calculate the load flow result of the circuit. At every simulation time step, newly updated active and reactive power outputs are calculated in Python and sent to the ECG models in CYME. Based on the power output, CYME then calculates the RPA voltage for each ECG and send the voltage information back to Python to move the simulation into the next time step. This approach has proven to be very effective in analyzing a broad set of parameters to assess volt-var control induced instability [3].

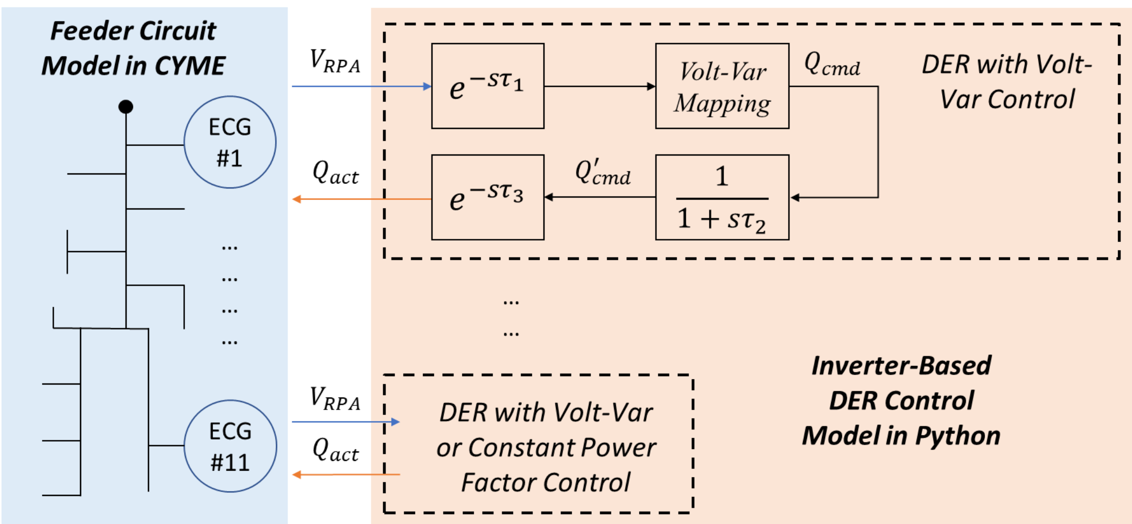


Fig.3. Illustration of the simulation approach and the dynamic DER model

The block diagram for the DER model in Python with volt-var control is also shown in Fig.3. $e^{-s\tau_1}$ represents the voltage measurement delay. Based on the measured voltage, the volt-var mapping block generates a reactive power command (Q_{cmd}) according to the volt-var curve settings. The first order lag function with a time constant of τ_2 is to slow down the tracking of Q_{cmd} to achieve the open loop response time required in IEEE Std 1547™-2018. $e^{-s\tau_3}$ represents the delay caused by inverter power and current control loops to track the reactive power command. Note that utility operaters can specify the volt-var curve and open loop response time settings if the DER is IEEE Std 1547™-2018 compliant. However, the voltage measurement delay (τ_1) and internal control procession delay (τ_3) varies and are often considered proprietary to the inverter manufacturer, hence hard to obtain. As discussed in [3], in a commercial inverter, these time delays can be a combination of time lags (e.g., a first order time lag) and pure time delays depending on the control implementation. However, it has been shown in [3] that pure time delay represents the worst case scenario and is therefore considered in this study to obtain conservative results since information on the actual delay is missing.

With this modeling approach, τ_1 and τ_3 can be considered together as $\tau_1 + \tau_3$ represents the total pure time delay in the control loop. For simplicity, $\tau_1 + \tau_3$ is termed measurement and processing delay associated with DER volt-var control hereinafter.

4. Evaluation of Volt-Var Control Stability through Dynamic Simulation

4.1 Stability Mechanism and Key Impacting Factors

Before presenting the dynamic simulation results, it is worthwhile to recap the mechanism and key impacting factors of volt-var control stability that has been revealed in [2] and [3]. With reference to the volt-var control model in Fig. 3, inside the DER control, the key factors affecting volt-var control stability are the measurement and processing delay, the open loop response time, and the slope of the volt-var setting curve (between the points (V_1, Q_1) and (V_2, Q_2), and between (V_3, Q_3) and (V_4, Q_4)). Risk of volt-var control instability increases with longer measurement delay, higher volt-var slope and shorter open loop response time.

Another key factor that affects the volt-var control stability is the voltage sensitivity to DER reactive power output at the RPA (dV/dQ). The sensitivity is highly dependent on DER interconnection location and the impedance of the external system (from RPA to feeder substation). When the DER is connected at a location with low short circuit ratio (SCR), which often indicates long distance from the substation, the voltage sensitivity is high and so is the risk of volt-var control instability.

On a high level, volt-var control instability can be understood as follows: suppose the DER volt-var control is responding to a high voltage event at its RPA by absorbing reactive power. As more reactive power is absorbed, the RPA voltage is reduced below the reference voltage. However, because of the measurement and processing delay, the DER does not "see" the voltage drop in real time and hence only start responding to it when the voltage drop is already significant. After the DER responds to the voltage drop by injecting reactive power, the RPA voltage goes higher than the reference voltage and again the DER fails to adjust its reactive power before a large voltage increase. This pattern repeats and causes sustained voltage oscillations in the system. Based on this, it can be understood that longer measurement and processing delay is detrimental to volt-var control stability. Moreover, higher voltage sensitivity, higher volt-var slope and shorter open loop response time all contribute to moving the voltage at the RPA faster and more significant, therefore also adversely affects the control stability.

4.2 Evaluation of Instability Risk when Activating Volt-Var Control at Multiple DERs

4.2.1 Volt-var control activated at all the PV sites

The scenario where all 11 PV sites activate volt-var control with IEEE Std 1547™-2018 default settings is analyzed first. The volt-var curve setting is shown in Fig. 4. The reactive power capability of each PV site is assumed to be 0.44 pu based on the plant kVA rating, which is the minimum required capability for Category B DERs in IEEE Std 1547™-2018. With these settings, the slope of the volt-var curve is calculated to be 7.33. Note the slope is unit-less since it is per unit reactive power over per unit voltage. The open loop response time is set to the default 5s and the measurement and processing delay is assumed to be 0.2s.

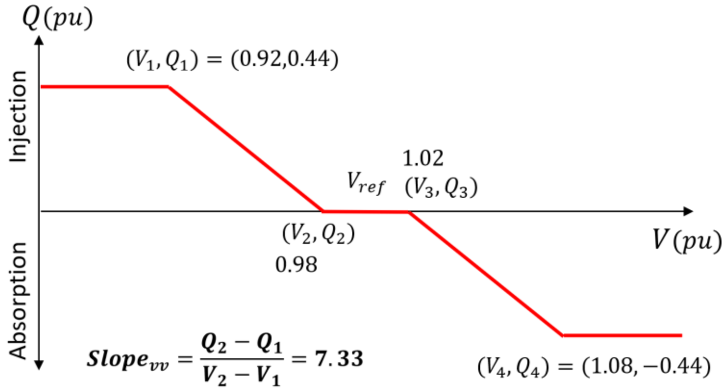


Fig.4. Volt-var curve with IEEE Std 1547™-2018 default settings

With these default settings, the dynamic simulation results are shown in Fig. 5. The RPA voltage and reactive power output are shown for each group of PV sites. Note that since the voltage and reactive power responses from PV sites inside the same group are similar, the response from one PV site is selected to represent the response of the whole group. The PV sites are operating with unity power factor before 0s without any voltage support. As a result, back-feeding from the PV sites causes the RPA voltages to be above 1.05 pu. At time $t = 0$, volt-var control with IEEE Std 1547™-2018 default settings is activated at each PV site, following which the PV sites absorb reactive power and the RPA overvoltages are reduced. At time $t = 4s$, as another disturbance, the loads on the feeder are reduced uniformly to 80% of the original value to increase PV back-feeding. In response, the PV sites absorb more reactive power according to the volt-var curve. As shown by the simulation results, the response in inverter reactive power output and the RPA voltage is stable without any oscillations. This indicates that with IEEE Std 1547™-2018 default settings, volt-var control can be activated at all the PV sites without causing voltage oscillations.

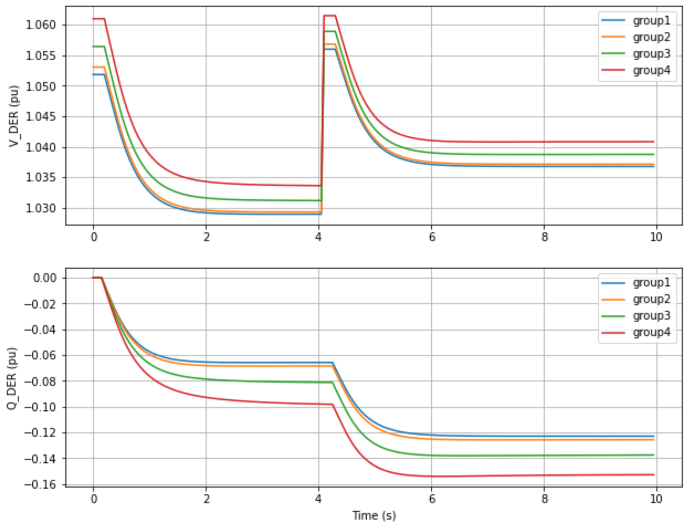


Fig.5. Simulation results with IEEE Std 1547™-2018 default settings

To analyze the sensitivity of volt-var control stability to its control settings and the measurement and processing delay, additional simulation case studies were conducted. For this set of studies, the volt-var curve setting without the deadband (shown in Fig. 6) is utilized. The parameters considered for each case study are illustrated in Table I, where OLRT stands for open loop response time and M&P delay for measurement and processing delay.

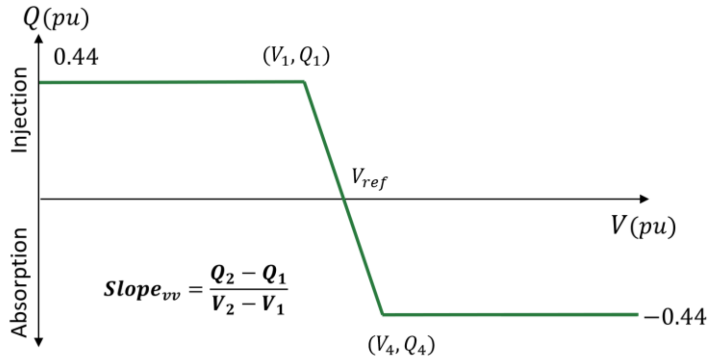


Fig.6. Volt-var curve settings considered in the additional case studies

Table I : Case study parameters (same parameters for all the PV sites)

Case study #	volt-var slope	OLRT	M&P delay
1	8.8	1.2s	0.2s
2	22	1.2s	0.2s
3	22	4.2s	0.2s
4	22	1.2s	0.05s

For each of the case studies, simulation results considering the same events (i.e., activation of volt-var control and load step decrease) are shown in Fig. 7. Note that these events are also considered for all the cased studies presented in the remainder of this paper. For case study 1, the volt-var slope is increased and the OLRT is reduced from the default settings. This causes the oscillation damping to decrease and significant voltage and reactive power oscillations are observable, even though they eventually damp down towards a constant steady state value. Another observation is that the steady state voltage after the oscillations damp down is closer to the reference voltage at 1pu, compared with the results with IEEE default settings. This demonstrates that higher volt-var slope improves the effectiveness of voltage regulation (i.e., the steady state voltage is closer to the reference), at the cost of higher instability risks.

When the volt-var slope is further increased, as in case 2, the oscillations become worse as the oscillation magnitude is large and sustained, which will cause significant flicker issue on the feeder. With this high volt-var slope, cases 3 and 4 demonstrate two methods to eliminate the sustained oscillations. In case 3, the OLRT is increases and as a result the damping of the oscillations gets improved. Case 4 demonstrates that if the M&P delay in the DER control is less, the oscillations can be stable as well.

Results from these studies are in line with the conclusions from previous EPRI studies [2], [3]. Since the M&P delay is not controllable by utility operators, if high volt-var slope settings are used at all the PV plants to better regulate the steady state voltage, the OLRT should be set to a sufficiently large value to ensure stability. The threshold for the OLRT depends on the M&P delay and particular feeder conditions, which can be assessed using the simulation approach presented in this paper.

4.2.2 Two PV sites with volt-var control activated, others with constant power factor control

As another comparison, the scenario where volt-var control is only activated for the two PV sites inside group 3 is analyzed. The volt-var control settings are the same as those listed for case 2 in Table I. All the other PV sites are operating with constant power factor control (0.98, absorbing). From the results shown in Fig. 8, and compare with Fig. 7 (b), it can be concluded that activating volt-var functions on a smaller number of DERs on a feeder improves the stability. The reason is that when volt-var control is activated at more DERs, the RPA voltage at a certain DER is also affected by the reactive power output from other DERs. Assuming that the reactive power output of all the DERs oscillate in phase (going up or down at the same time), which is true for all the simulation results shown so far, it essentially increases the voltage sensitivity at the DER and therefore increases the instability risk.

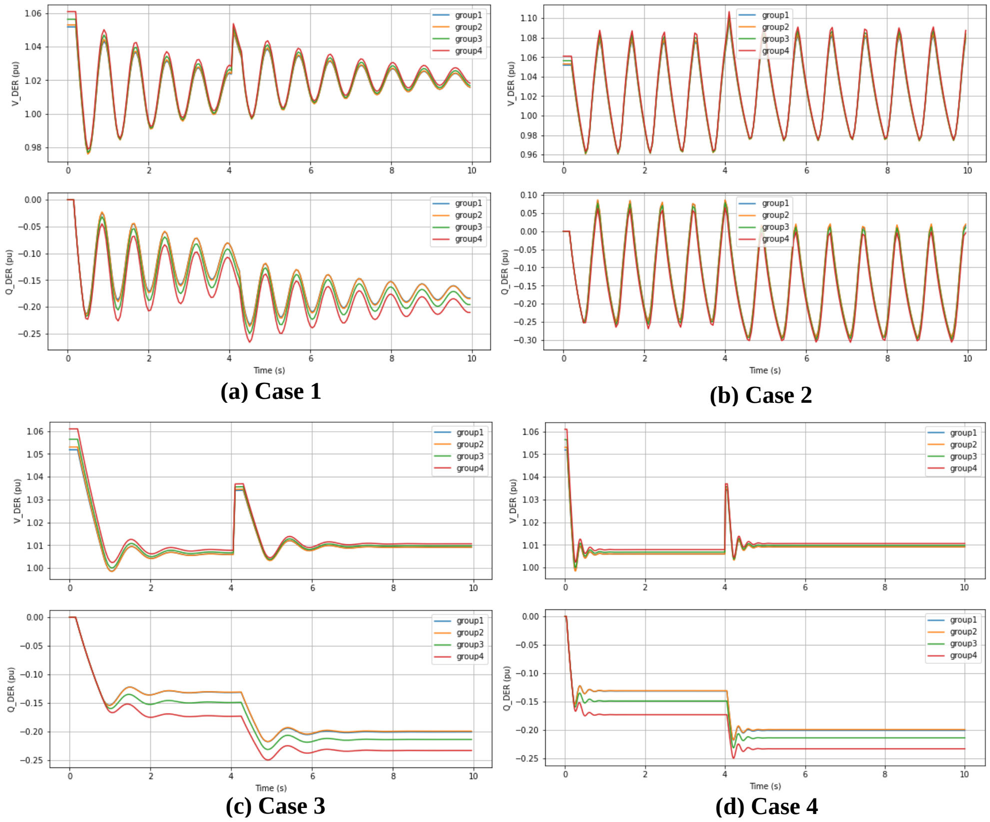


Fig.7. Simulation results of additional case studies

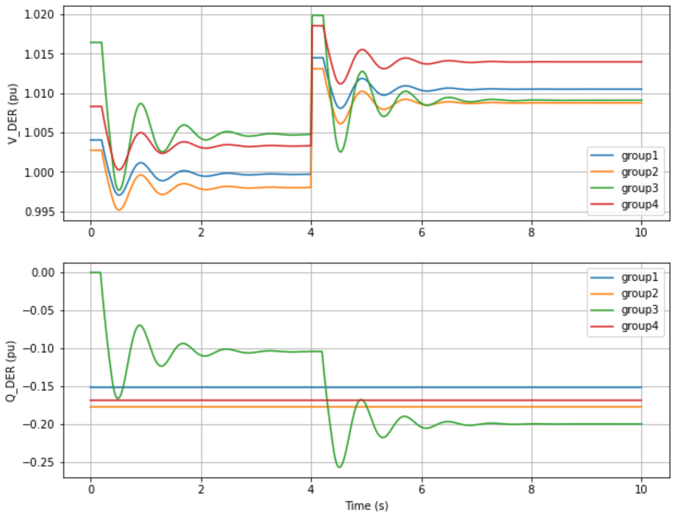


Fig.8. Simulation results with volt-var control on two PV sites

4.3 Evaluation of Control Interaction between Multiple DERs

Analyses up to this point assume that the same volt-var control settings are used for the DERs with volt-var control activated and the M&P delay is the same for all the DERs. A question to address next is whether non-uniform control settings or M&P delays can cause "fighting" between volt-var controls at different DERs. An example of control "fighting" could be as one DER is trying to lower the feeder voltage by absorbing reactive power, another DER is doing the opposite. If such interaction occurs, whether it adversely affect the control stability needs to be assessed. Another question to explore is whether non-uniform control settings can introduce additional oscillation modes (i.e., having oscillations with different frequencies in voltage and reactive power). It can be seen from the results up to this point that the oscillations at different DERs all have one frequency.

To address these questions, a scenario is constructed where the PV sites in group 1 and group 3 have volt-var control activated while all the other plants are working at a constant power factor of 0.98 (absorbing). 10 case studies are considered. For all the studies, the parameters listed in Table II is applied for group 1 PV sites while the volt-var control and M&P delay parameters for group 3 PV sites are varied according to Table III.

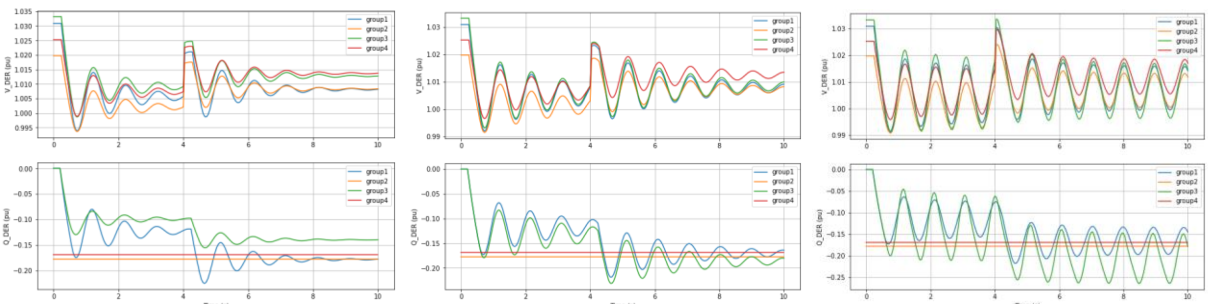
Table II : Case study parameters for group 1 PV sites

Case study #	volt-var slope	OLRT	M&P delay
1-10	22	2.25s	0.25s

Table III : Case study parameters for group 3 PV sites

Case study #	volt-var slope	OLRT	M&P delay
1	11	2.25s	0.25s
2	22	2.25s	0.25s
3	44	2.25s	0.25s
4	11	10.25s	0.25s
5	11	2.25s	0.25s
6	11	1.25s	0.25s
7	11	2.25s	0.1s
8	11	2.25s	0.25s
9	11	2.25s	0.5s
10	11	2.25s	0.8s

Case studies 1 to 3 analyze potential control interaction with non-uniform volt-var slope settings and the results are shown in Fig. 9. As can be seen, with increasing volt-var slope at group 3 PV plants, the oscillation damping decreases and is observed at the RPA voltages of all the PV sites. Oscillations in reactive power output have similar frequency and damping at group 1 and group 3, which indicates a single oscillation mode in the system. Meanwhile, the reactive power oscillation at group 1 and group 3 are in phase in all the three cases. Therefore, non-uniform volt-var slope settings at different DERs do not introduce control “fighting” in the case studies.

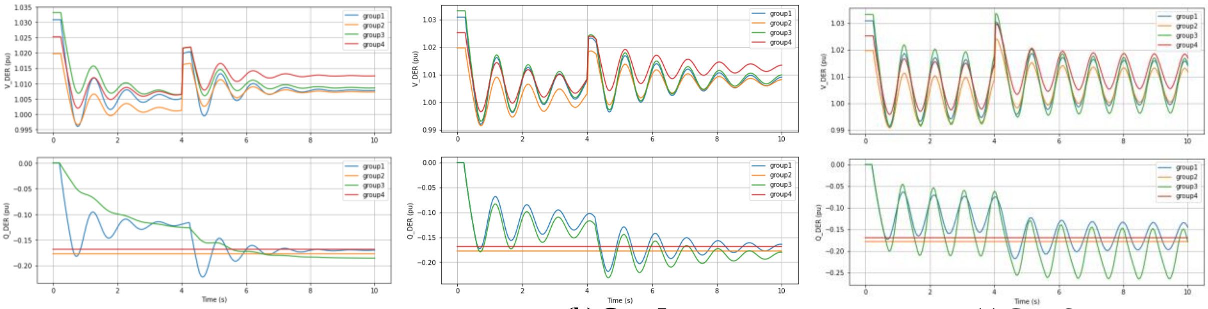


(a) Case 1 **(b) Case 2** **(c) Case 3**

Fig.9. Simulation results with non-uniform volt-var slope settings

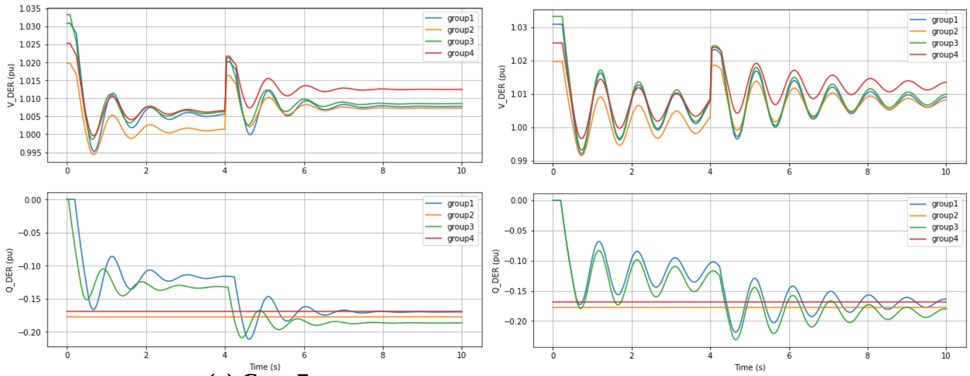
Similarly, case studies 4 to 6 analyze potential control interaction with non-uniform volt-var control OLRT settings and the results are shown in Fig. 10. As expected, with decreasing OLRT at group 3 PV plants, the oscillation damping decreases and is again observable at the RPA voltages of all the PV sites. Based on the oscillation frequency, damping and phase, it can be seen that non-uniform volt-var control OLRT settings at different DERs do not introduce control “fighting” in the case studies.

The last set of case studies (cases 7 to 10) analyzes potential control interaction with non-uniform M&P delays at different DERs and the results are shown in Fig. 11. Extrapolating from the studies with uniform M&P delays, increasing M&P delay at group 3 PV sites should always decrease the oscillation damping and increase the instability risk. This is true when comparing case 7 with case 8, and case 9 with case 10. However, comparing case 8 with case 9, the increase in M&P delay actually improves the damping. Comparing the four cases, it can be seen that when the M&P delays are not the same for the two groups (cases 7, 9 and 10), the oscillations at different groups are no longer in phase. The out of phase oscillation indicates interaction between the two groups. However, instead of causing adverse impact on system stability, the interaction seems to improve the oscillation damping. This can be the potential cause of the higher damping in case 9 compared to case 8. When the M&P delay at group 3 is further increased to the value in case 10, the benefits of control interaction can no longer offset the adverse impact of increasing the M&P delay and the oscillation becomes unstable.

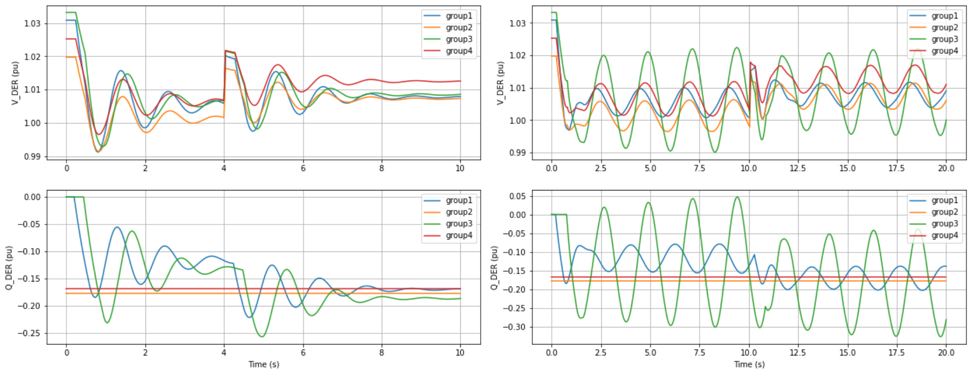


(a) Case 4 **(b) Case 5** **(c) Case 6**

Fig.10. Simulation results with non-uniform OLRT settings



(a) Case 7 **(b) Case 8**



(c) Case 9 **(d) Case 10**

Fig.11. Simulation results with non-uniform M&P delay

In summary, based on these preliminary case studies on the NG feeder, it appears that non-uniform volt-var slope settings, OLRT settings and M&P delays at different DERs do not introduce additional oscillation mode. Voltage and reactive power oscillation of the same frequency and damping is observed across the feeder. Moreover, non-uniform M&P delay causes phase shifts of the oscillations at different feeder locations and can increase the interaction among multiple DERs. However, instead of negatively affecting the stability, the increased interaction seems to help with oscillation damping when the M&P delays are bounded within a certain range. As mentioned earlier in the paper, the M&P delay is not controllable by the utility operator and its information is hard to obtain from the inverter manufacturers. Therefore, diversifying the M&P delays on a feeder to improve stability is hard to pursue in practice.

5. Conclusion

This paper evaluates the risk of voltage oscillations on a NG feeder when multiple PV sites activate volt-var control functions. Results indicate that while volt-var control is stable with IEEE Std 1547™-2018 default settings, further increasing the volt-var slope and/or reducing the open loop response time can lead to unstable voltage oscillations, especially when all the PV sites on the feeder have volt-var control activated. Measurement and process delay associated with the DER volt-var control is demonstrated to be another key factor that affects the volt-var control stability. While information on the delay can be hard to obtain as it is often considered proprietary by inverter manufacturers, it is important to evaluate the voltage oscillation risk conservatively with the worst-case delay information, especially when aggressive volt-var control settings are to be applied. The dynamic modeling and simulation approach presented in this paper can be leveraged for such evaluations. Moreover, simulation case studies in this paper reveal that non-uniform volt-var slope and open loop response settings at different DERs are unlikely to cause control "fighting" among the DERs. Even though non-uniform measurement and processing delay at different DERs can increase the interaction among the DERs, the interaction is found to be beneficial to the oscillation damping when the delays are bounded within a certain range.

BIBLIOGRAPHY

[1] *Application Guidelines for DER Advanced Functions & Settings*. EPRI, Palo Alto, CA: 2019. 3002015738.

[2] *Oscillation Mechanism and Setting Guideline for Inverter Volt-Var Control*, EPRI, Palo Alto, CA: 2020. 3002019776.

[3] *Feeder Closed Loop Control Interactions on High Penetration DER Systems*, EPRI, Palo Alto, CA: 2020. 3002018657.

[4] *Stability Analysis and Volt-Watt and Volt-Var Control Setting Guideline for DERs*, EPRI, Palo Alto, CA: 2021. 3002021716.

[5] W. Wang, X. Shi, C. Brewster and A. Huque, "Oscillation Mechanism and Setting Guideline for Inverter Volt-Var Control," 2020 47th IEEE Photovoltaic Specialists Conference (PVSC), 2020, pp. 2032-2039.

[6] W. Wang, W. Ren, A. Huque, D. V. Zandt and R. Walling, "Stability Analysis and Volt-Watt Control Setting Guideline for Distributed Energy Resources, " 2022 49th IEEE Photovoltaic Specialists Conference (PVSC), 2022.

[7] A. Singhal, V. Ajjarapu, J. Fuller and J. Hansen, "Real-Time Local Volt/Var Control Under External Disturbances With High PV Penetration," in IEEE Transactions on Smart Grid, vol. 10, no. 4, pp. 3849-3859, July 2019.

[8] J. Schoene et al., "Investigation of oscillations caused by voltage control from smart PV on a secondary system," 2017 IEEE Power & Energy Society General Meeting, Chicago, IL, 2017, pp. 1-5.

[9] F. Andrén, B. Bletterie, S. Kadam, P. Kotsampopoulos and C. Bucher, "On the Stability of Local Voltage Control in Distribution Networks With a High Penetration of Inverter-Based Generation," in IEEE Transactions on Industrial Electronics, vol. 62, no. 4, pp. 2519-2529, April 2015.

[10] P. Jahangiri and D. C. Aliprantis, "Distributed Volt/VAr Control by PV Inverters," in IEEE Transactions on Power Systems, vol. 28, no. 3, pp. 3429-3439, Aug. 2013.

[11] M. Farivar, L. Chen and S. Low, "Equilibrium and dynamics of local voltage control in distribution systems," 52nd IEEE Conference on Decision and Control, Florence, 2013, pp. 4329-4334.

[12] National Grid - Massachusetts System Data Portal, available online at https://ngrid.apps.nationalgrid.com/NGSysDataPortal/MA/index.html