Sustainable Technologies
EVALUATION PROGRAM

Managing Volt/VAR in Active Distribution Networks Using Distributed Generation Units and Peer to Peer Communication

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Report authors:

Dr. Hany E.Z. Farag, Ph.D, P. Eng
Assistant Professor
Electrical Engineering and Computer Science
York University

Leigh St. Hilaire, B.A.Sc.[1]
Project Manager, STEP
Toronto and Region Conservation Authority
101 Exchange Avenue
Vaughan, Ontario
E-mail: lsthilaire@trca.on.ca

Nader El-Taweel, MASc
Ph.D Candidate
Electrical Engineering and Computer Science
York University

Shivam Saxena, MASc, P. Eng
Ph.D Candidate
Electrical Engineering and Computer Science
York University

Documents prepared by the Sustainable Technologies Evaluation Program (STEP) are available at www.sustainabletechnologies.ca.

[1] Corresponding author.

THE SUSTAINABLE TECHNOLOGIES EVALUATION PROGRAM

The Sustainable Technologies Evaluation Program (STEP) is a multi-agency initiative developed to support broader implementation of sustainable technologies and practices within a Canadian context. STEP works to achieve this overarching objective by:

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- Assessing technology implementation barriers and opportunities;
- Developing supporting tools, guidelines and policies;
- Delivering education and training programs;
- Advocating for effective sustainable technologies; and
- Collaborating with academic and industry partners through our Living Labs and other initiatives.

Technologies evaluated under STEP are not limited to physical devices or products; they may also include preventative measures, implementation protocols, alternative urban site designs, and other innovative practices that help create more sustainable and livable communities.

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The contributions from all above parties are greatly appreciated by the project team.

NOTICE

EXECUTIVE SUMMARY

In the modern age of the *Smart Grid*, Local Distribution Companies (LDCs) are under tremendous pressure to increase the penetration of renewable distributed generation (DG) units within the electrical power grid. However, the large-scale deployment of these DGs are severely curtailed due to their negative impacts on system stability. Voltage regulation becomes particularly challenging for LDCs because the variable power production of weather dependent DGs produce distorted voltage profiles within distribution feeders. Furthermore, the power injections from DGs connected to the feeder may also push the voltage outside of the acceptable range, causing damage to grid assets when overvoltage conditions occur. With voltage control being an extremely crucial part of overall power system control, LDCs are facing an increasingly stiff challenge: integrating large numbers of DG units while still maintaining an acceptable Quality of Service (QoS).

This project seeks to address these challenges by designing a distributed, multi-agent control strategy to perform voltage regulation within active distribution networks (ADNs). The ADN is spatially decentralized into separate zones, each of which are assigned to an entity known as an intelligent agent. This software-based agent uses any available controllable devices within its zone to regulate the zonal voltage, including smart inverters and energy storage system. If the violation persists, agents can then request neighboring agents for help, where the responding agent will first evaluate any zonal or physical constraints and then respond with appropriate control actions. The ability of agents to work together establishes a cooperative and cohesive approach to voltage regulation, offering significant upgrades in latency, complexity, and reliability over legacy control schemes that are traditionally centralized.

All communication between agents is facilitated using a real-time, Internet of Things (IoT) based middleware entitled Data Distribution Service (DDS). DDS is fully distributed, highly scalable, and provides deterministic behavior within real-time applications. It is also fully interoperable, thereby increasing system flexibility. Due to these features, it is well suited to the requirements of multi-agent systems, particularly for smart grid applications that require low latency and high bandwidth communication mediums.

The implementation of the control strategy can also be extended to LDC system operators that may require ancillary grid services that could be provided by distributed agents. An example request could be a reactive power injection to boost the system voltage at a specific point within the network. The request would be evaluated by local agents, who would then determine their combined capability to handle the request, and then coordinate their actions to export the maximum possible reactive power without violating zonal constraints. This feature is implemented as an out of the box software application that can be deployed in utility control centers (UCCS).

The proposed control strategy was tested in both simulation and real-world experiments at the Living City Smart Grid (LCSG), located in Vaughan, Ontario. The LCSG has over 50 kW of renewable power production capability and is equipped with smart inverters, energy storage systems, as well as a real-time data-acquisition and monitoring system. Simulation results show that the agents can resolve overvoltage violations at the facility by absorbing reactive power from the grid, allowing maximum active power generation to be harvested. This leads to a higher penetration of renewable energy to the grid (almost 9%), which also results in further greenhouse gas (GHG) emission reduction (over 520g CO2e daily). Real-world tests show that emergency grid support requests can be processed and executed almost instantaneously. On the qualitative side, the overall framework is shown to be completely interoperable by enforcing the use of strictly open communication platforms (DDS) as well as adhering to proper communication standards (SunSpec, International Electrotechnical Commission 61850). The framework can be joined, configured, or used by any software running on any operating system and implemented using any programming language.

The main conclusion drawn from this project is that grid assets that perform local control can be empowered further if their control schemes are coordinated with other similar devices. Multi-agent-based control/communication frameworks are an ideal candidate to facilitate this task. Such frameworks have the capability to take truly intelligent decisions to stabilize, and even optimize the grid. A wide deployment of these frameworks has the potential to result in a power system that is efficient, resilient, and above all, environmentally conscious.

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1.0 INTRODUCTION

1.1 Motivation

Aggressive climate change and sustainability initiatives have brought much needed attention to the overall operation and architecture of electric power systems. Under the *Smart Grid* paradigm, centralized legacy power systems are slowly being restructured into decentralized, modular systems that are serviced by distributed generation (DG) units. Although the deployment of DGs within active distribution networks (ADNs) have many potential benefits, it also introduces unintended technical challenges. These challenges include: reverse power flow due to excessive DG power production, overvoltage conditions at the electrical connection point (ECP) of the DG and the feeder, unstable voltage profiles due to weather intermittency, as well as the miscoordination of protective grid assets that are not designed for two-way power flow [1]. Nevertheless, Local Distribution Companies (LDCs) are under extreme pressure to ramp up the large-scale deployment of DG units and are facing tremendous difficulty given these complex challenges.

Recent modifications to DG interconnection standards (*IEEE 1547 – 2014* and *CSA-C22.2 NO. 257- 2006*), as well as technological advancements within the inverter of the DG unit have given hope to mitigating the aforementioned challenges. Previous iterations of the standards dictated that DG units were required to disconnect from the grid if the voltage or frequency at its ECP fell out of range (+/-5%) [2] . However, the new iterations of these standards permit the DG units to "ride-through" and provide local grid stabilization support by modulating their real/reactive power output in real-time. This allows the DG inverter to regulate the voltage at the ECP based on pre-configured setpoints. These inverter-based DG units are often referred to as *smart inverters*, capable of sensing local conditions and reacting autonomously on a cycle-to-cycle basis.

While the adoption of smart inverters is a step in the right direction, significant questions and challenges remain to be solved before their wide-scale deployment can begin. Conventional control strategies within electrical power systems are typically centralized, and as such, would involve the continuous monitoring and changing of the inverter setpoints by grid operators. Considering that there is potential for thousands, if not millions of inverters to be deployed within the power system over the next decade, such an approach is not scalable due to the sheer latency and complexity of centralized systems [3]. Secondly, these DG units execute control actions locally, and do not communicate or coordinate their actions with each other or any other grid asset (load tap changers, automatic voltage regulators etc.). Given this, the miscoordination between such devices remains a significant unresolved problem.

This project focuses on addressing these challenges by developing distributed control strategies to coordinate the behavior of smart inverters and grid assets to perform voltage regulation within ADNs. The control schemes are coordinated by software based intelligent agents, each of which takes responsibility for a spatial area and retains supervisory control of all grid assets within their jurisdiction (referred to as a zone). The agents first seek to regulate the voltage profile in their zone, and if unable to, request assistance from neighboring agents (Figure 1). Utilizing real-time, Internet of Things (IoT) based communication protocols such as Data Distribution Service (DDS), the overall framework ensures that agents can react to local disturbances quickly and efficiently, exchanging information with neighboring agents rather than waiting to receive control actions from a central control center. As a result, an agent-based approach can span a larger spatial distance, and overall grid operations can be more efficient, dynamic, and robust.

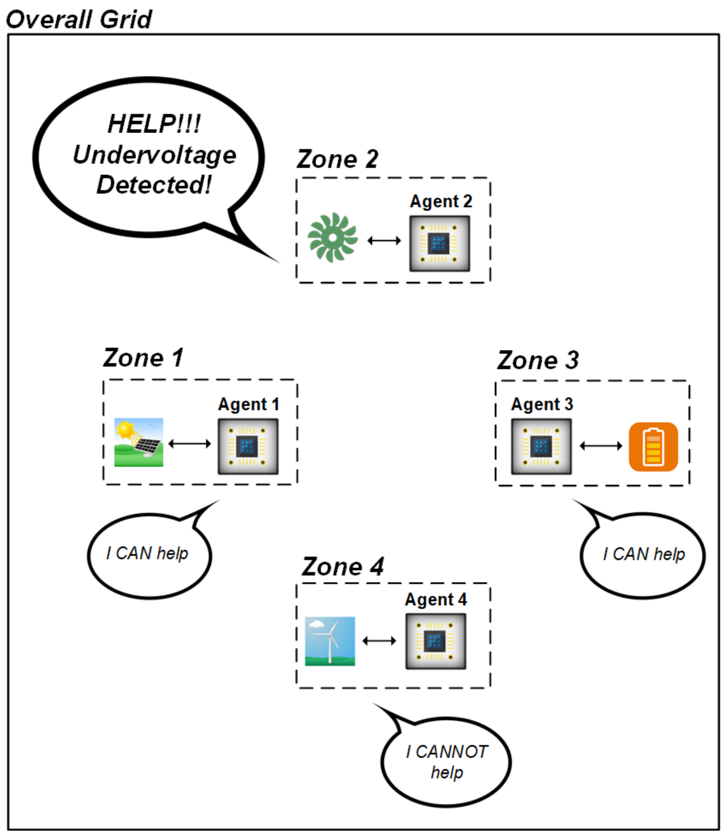

Figure 1 – Example of a power grid spatially partitioned into 4 zones. Agents work cooperatively and can ask each other for assistance to help mitigate potential zonal violations.

Another crucial aspect to the project is to help LDC operators visualize and control distributed grid assets remotely. As such, a utility grade software (based on the IEC 61850 standard) has been developed to enable two-way communication between a utility control center and distributed grid assets that are governed by intelligent agents. This software acts as an interface between the agents in the field and any LDC grid operator, facilitating requests for power to be injected/absorbed to/from the grid. Potential use cases for this software are to request reactive power injections for undervoltage situations, or to derate active power injections from DG based inverters in overvoltage situations. As a result, the developed framework has the capability to perform hybrid control: utilizing local agents to mitigate local voltage irregularities in real-time, as well as allowing LDC operators to override local control schemes to facilitate grid support requests in emergency conditions.

In summary, the primary objectives of the project are listed below:

1) Design distributed voltage control algorithms (primarily Volt/VAR, Volt/Watt based) to perform voltage regulation at the electrical connection point (ECP) between smart inverters and the distribution feeder.

2) Develop an agent-based communication framework to test the implementation of the control algorithms developed in (1).
3) Implement a utility grade software (Utility Control Center Software – UCCS) that allows LDC operators to view/control distributed grid assets via remote control and respond to emergency requests.
4) Test and document the outputs of the voltage control scheme in simulated case studies, as well as in a real-world implementation.

1.2 Project Themes

This project is built on the foundation of three related, yet distinct research themes. These themes include: Multi-Agent System Control (MAS), IoT Communication, as well as Interoperability Standards (Figure 2). As such, it is useful to provide the necessary background details for these themes and explore how they relate to the overall project.

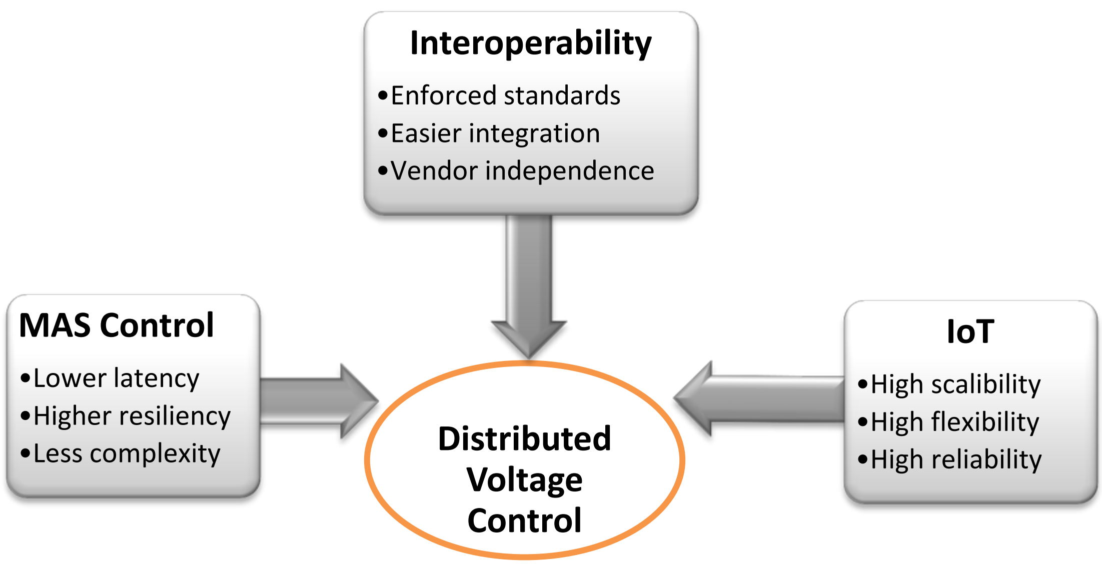

Figure 2 - Research themes that are central to the developed control/communication framework.

Multi-Agent System Control

The roots of MAS control lie in the concept of decentralization, which is in direct contrast to conventional power system control that has typically used centralized control strategies [4]. However, centralized systems have several shortcomings. First, the sheer quantity of data processed by the control center requires a great deal of computational resources. Second, measurement units located far away from the control center take more time to transmit their measurements, introducing latency into the system. Third, the centralized control centers have a single point of failure, introducing a degree of vulnerability to the overall power system [5].

MAS control addresses these shortcomings by spatially dividing the overall network into zones and empowering local agents to take local decisions. This significantly reduces computational complexity since each agent is burdened only with the data/measurements of its own zone. Furthermore, overall system latency is reduced because the agents are in closer proximity to the measurement units. Finally, the overall system is more resilient because of a lack of dependence on the control center. MAS is especially suited to smart grid applications, where the growth of highly dynamic distributed energy resources (DERs) will be seen in the coming years. Agent based control will be crucial in harnessing the true potential of these DERs [6].

IoT Communication

The IoT is the realization of a concept where every conceivable device, whether physical or virtual, has a presence on the internet. Each device, referred to as a thing, can therefore interact and exchange information with other things in a peer to peer (P2P) manner. This concept can further be extended to the Industrial-IoT (IIoT), where things are able to cooperate with each other in an effort to make cohesive decisions that better automate industrial processes. It is estimated that by the year 2030, upwards of 1 trillion devices will be connected to the internet [7]. To mitigate issues of size and latency, IoT frameworks are based upon distributed, peer to peer (P2P) communication architectures that are inherently scalable due to a lack of centralization. Furthermore, these frameworks strive to promote interoperability and facilitate information exchanges between devices (D2D), machine (M2M), and servers (S2S).

As such, the union of IoT communication frameworks and MAS control schemes could offer tremendous benefits to the overall power system given their shared philosophy of decentralization and coordinated P2P decision making. Agents within the system could utilize IoT communication frameworks to coordinate their actions harmoniously to provide optimal control of a spatial area. Such integrated systems would help to mitigate challenges of latency and complexity given their inherent scalability and flexibility, while also unlocking the true potential of fast acting smart devices that the agents would retain supervisory control over.

Interoperability Standards

Tying the above two research themes together is the concept of interoperability, which is the ability for any system to understand and exchange information with any other system in a seamless manner. Such approaches lead to system architectures that are extensible, scalable, and cohesive. One of the more common standards for interoperability in the smart grid field is International Electrotechnical Commission 61850 (IEC 61850), which provides abstract models of all power system components and their services. Additionally, IEC 61850 provides specifications for all forms of power system communication, including how components should exchange information with each other. This level of interoperability allows all 61850 compliant devices to essentially work in "plug and play" fashion, which is an important requirement of the future smart grid [7]. Originally intended for substation automation, IEC 61850 has since expanded its domain to DER modelling (IEC 61850-7-420) and inverter-based DERs (IEC 61850-90-7), among other related specializations. Both standards are adhered to in the development of the proposed control strategies within the project.

Both MAS control and IoT frameworks have the requirement of interoperability at their core. Agents within a network should be able to communicate with each other using a common syntax, while the framework they use to communicate with each other should be accessible to any platform. Driven by this motivation, the overall framework developed as part of this project is designed to be fully interoperable. This is achieved primarily by the usage of the DDS middleware as the message transport system between agents, which facilitates agent interaction regardless of platform or operating system. The framework also supports the SunSpec standard, which standardizes all advanced DER functions to common data/information models. Implementing the SunSpec standard at the LCSG ensures that system operators can install any SunSpec compliant DER without changing the underlying software architecture. This leads to a more extensible, flexible and robust system that is truly vendor independent.

1.3 Test Site – Living City Smart Grid

The implementation of the control strategy and accompanying utility control software (UCCS) was deployed at the Living City Smart Grid (LCSG), a state-of-the-art research facility belonging to the Toronto Region and Conservation Authority (TRCA). The LCSG has over 50 kW renewable power production capability, along with controllable smart inverters, battery banks and power quality meters (PQM). All assets are capable of being monitored in real-time via a high-speed, comprehensive data acquisition system. A basic schematic of all LCSG assets is shown in Figure 3. Although all LCSG assets can be monitored, only a few can be actively controlled. A summary of the controllable assets is given in Table 1. It should be mentioned that an additional 5 kW load is located at the Wind building; however, it can only be turned on and off.

Asset	**Specifications**	**Features**
SolarEdge 5000H Inverters	4 inverters - 5 kW each 3.3 kVAR capacity	Active power curtailment Reactive power control (cosPhi modulation, Volt/VAR curve, Volt/Watt curve, constant reactive power)
Schneider Xantrax 6848	6.8 kW inverter 75 kWh storage	Charge Battery Bank, Discharge Battery Bank

Table 1 – A description of the controllable LCSG assets and their control methods.

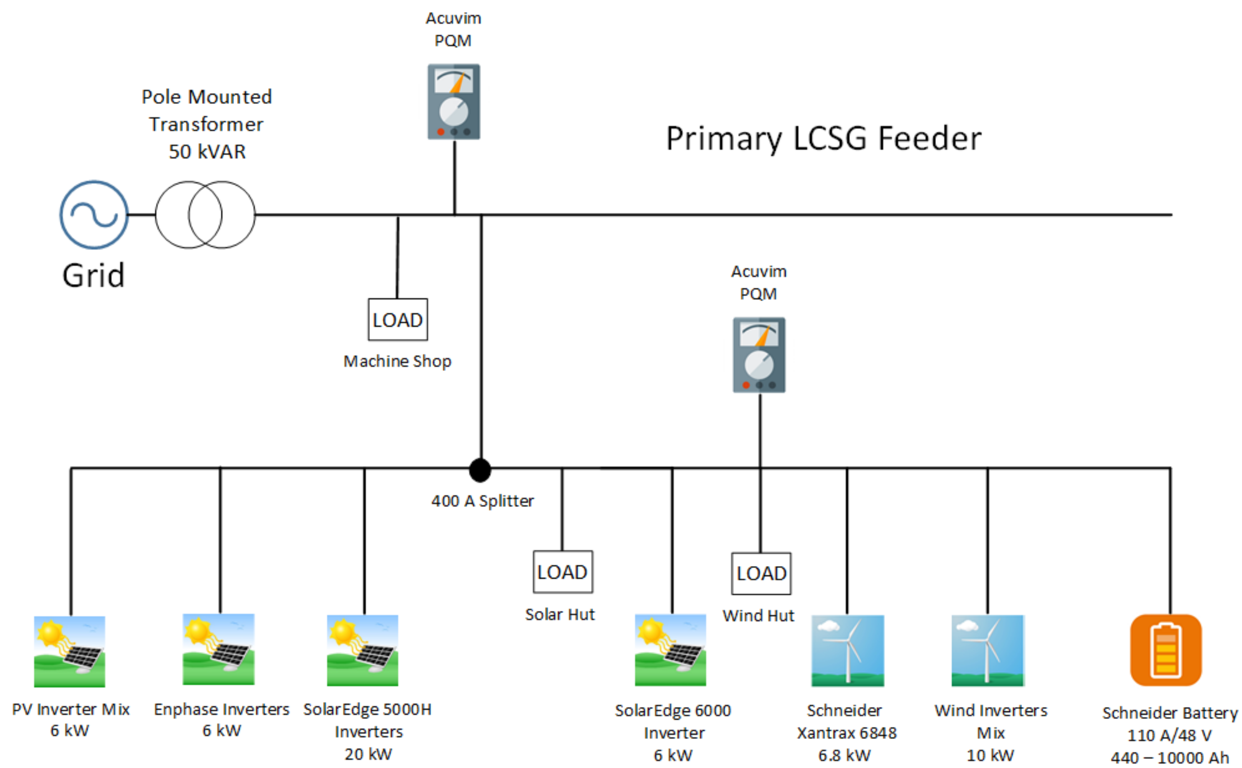

Figure 3 – A schematic of all LCSG assets.

1.3.1 LCSG Distribution Feeder Analysis

Prior to developing the voltage control strategy, an analysis of the LCSG feeder was conducted to assess the voltage issues that the LCSG was facing. The data was measured by the PQM closest to the utility PCC (machine shop) and taken at a sampling rate of 5 seconds.

CSA-C22.2 NO. 257- 2006 (CSA 257) specifies that the voltage at any point within the feeder cannot exceed 5% of the nominal 120 V standard [9]. This means that for low-voltage power systems in Canada, the feeder voltage must remain between 114 and 126 V for a single line, while for line to line voltage, the range is 228 – 252 V. As a result of very light loading, the LCSG facility regularly experiences overvoltage conditions. This can be seen in Figure 4, where Line 1 of the LCSG feeder exceeds the 126V threshold for 8 consecutive minutes from 12:24 PM to 12:32 PM.

The LCSG feeder also experiences a great deal of voltage fluctuation due to weather intermittency. Figure 5 shows a dual plot of the voltage of line 2 of the feeder, as well as irradiance measurements captured by an onsite pyranometer. Both plots show high degrees of fluctuation, with the line voltage having a maximum differential of 2.32V between sampling periods, while the maximum differential for the irradiance measurements is 360 W/m^2. The figure also shows a strong positive correlation between voltage and irradiance, which suggests that the feeder voltage is sensitive to active power injections. This can be expected since distribution feeders within low voltage systems typically have higher R/X ratios and are therefore sensitive to both active/reactive power injections [10].

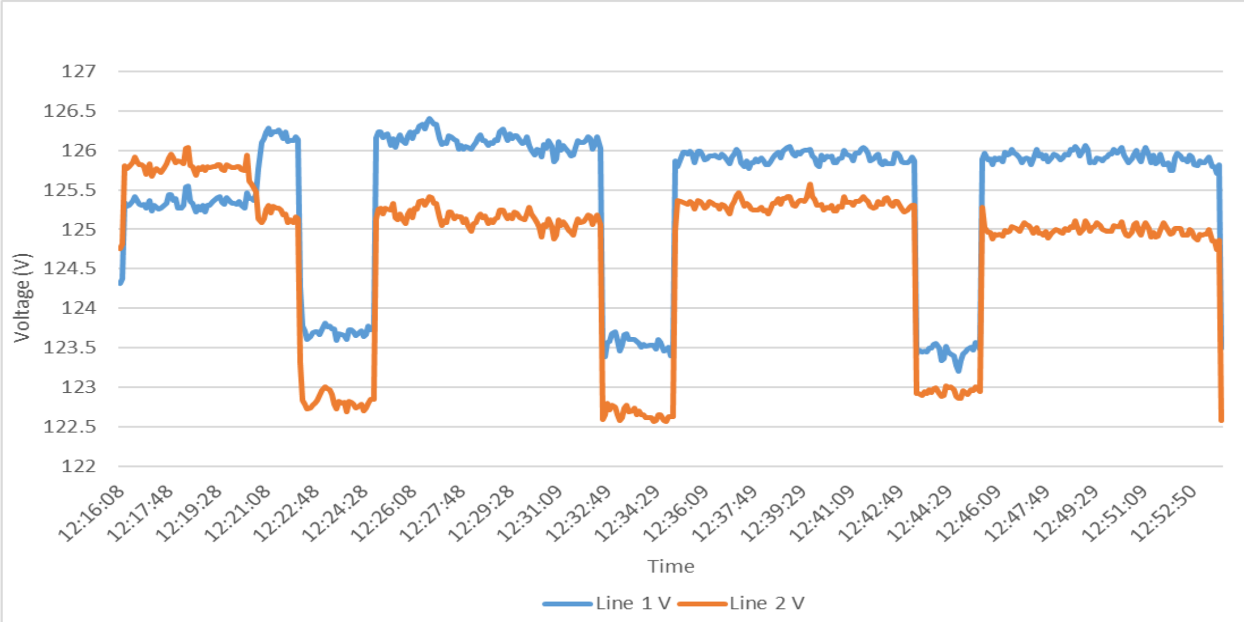

Figure 4 – Plot of both line voltages of the LCSG feeder. Both lines have peaks above the 126V threshold, with Line 1 going over the threshold for minutes at a time.

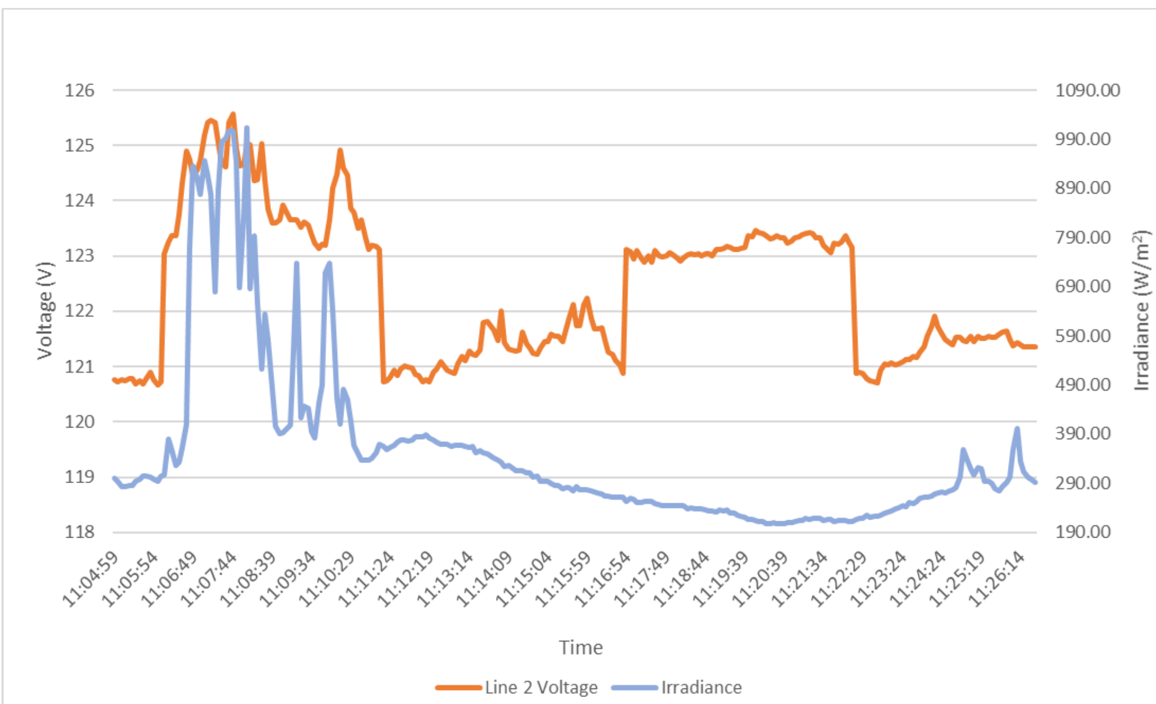

Figure 5 – Dual plot of Line 2 Voltage and irradiance, where significant fluctuations can be seen in voltage due to varying irradiance.

To confirm this, the voltage profile of a typical day is presented in Figure 6. The strong correlation between the two variables is the sun ascends to its peak values between 12PM and 3PM, the feeder voltage also hovers around the maximum 126V mark.

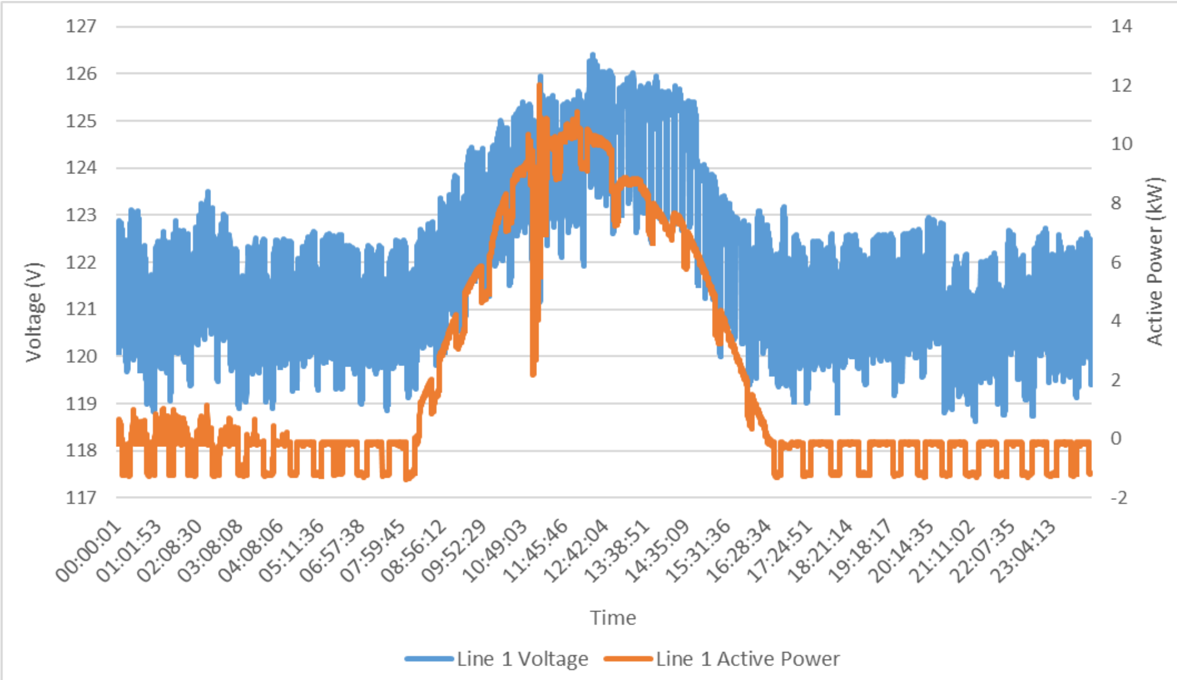

Figure 6 – Dual plot of Line 1 Voltage and Active Power, where a strong positive correlation can be seen between voltage and active power.

The following key findings can be summarized from the feeder analysis:

1) The LCSG suffers mostly from overvoltage problems.
2) The LCSG feeder experiences high degrees of voltage fluctuation.
3) The LCSG feeder voltage is sensitive to active power injections.

These findings will form the basis of the control algorithm to be developed for the LCSG. Namely, the control algorithm should seek to keep the line to line voltage of the feeder under 252 V.

1.4 Organization of Report

The organization of the report is as follows: Chapter 2 will focus on summarizing smart inverter control capability and will also determine the sensitivity of the LCSG feeder to *both* active and reactive power injections. Chapter 3 will provide background on the communication framework on DDS, while Chapter 4 will formalize the control strategy. Accompanying simulation and real-world results will then be discussed in Chapter 5. Chapter 6 will present the Utility Control Center software that LDC Operators can use to view/control the LCSG agents, while Chapter 7 will provide concluding remarks.

2.0 SMART INVERTER CONTROL

2.1 Overview of Smart Inverters

As mentioned earlier, given the possible negative impacts of interconnecting large quantities of renewable DER units to the grid, their penetration level is severely curtailed and strictly regulated. A local example can be given by Hydro One, one of the largest LDCs in Ontario, which allows a maximum of 7% of DG based power generation within their jurisdiction [11]. However, as of the late 2000's, new research has augmented the traditional inverter with extremely fast, accurate, and dynamic power electronics [13],[14]. These inverters are known as *smart inverters*, capable of modulating the quantity and type of power output (real, reactive) to provide ancillary grid support in real-time. To further increase the potential deployment of smart inverters, new standards such as California Rule 21 and amendments to the IEEE 1547 standard (IEEE 1547 a) are being made to allow the inverter to stay connected to the grid even if the voltage/frequency at the EPC falls out of range [15]. This functionality, known as "ride-through", allows the inverter to perform local control at its EPC to stabilize the grid instead of simply disconnecting. As such, the previously known "uncontrollable" inverter is now being viewed as the main tool to provide local control amongst DERs deployed within the grid. A summary of the control functions of smart inverters is presented in Table 2.

Smart Inverter Control Functions		
Function Name	**Description**	**Use Case**
Remote Connect/Disconnect	Inverter connects/disconnects from the power system in response to a remote signal from power system operator.	LDC disconnects batch of inverters because of feeder maintenance.
Active Power Curtailment	Inverter curtails the level of active power production from DGs.	Active power is curtailed to prevent reverse power flow.
Reactive Power Control	Inverter supplies/absorbs reactive power to/from the power system through power factor modulation.	Inverters used to perform conservation voltage reduction by lowering the system voltage.
Power Curves: Volt/VAR Frequency/Watt Volt/Watt	Inverter reacts to pre-defined power curves, sensing the local voltage/frequency and outputting the appropriate amount of VARs/Watts.	Inverters used to perform granular, non-linear control within networks with unspecified impedance (R/X).
Voltage/Frequency Ride Through	Inverter is allowed to operate between configurable voltage/frequency limits set by the system operator.	Inverters used to operate to stabilize the grid during severe voltage sags or in abnormal frequency situations.

Table 2 - Summary of Smart Inverter Control Functions and Potential Use Cases.

2.2 Smart Inverter Benchmarking

This section of the report will focus on performing benchmarks on the response times and accuracy of the SolarEdge 5000H smart inverters. Since the main functionality of the voltage regulation algorithms will rely on modifying active power (P) and reactive power (Q), the benchmarks will focus on testing active power deration and cosPhi (power factor) modulation. The following tests have a sampling period of 1 second, and all measurements were obtained from the inverter itself (see Technical Note 1 for more details).

In the first test, the active power curtailment feature of the inverter is tested. In intervals of approximately 30 seconds, the inverter is commanded to step down its active power production in terms of percentage of the total capacity (5 kW). From the data labels in Figure 7, it can be seen that the inverter responds almost instantaneously to the change in setpoint. The accuracy of the actual power output can be seen in Table 3, with the maximum deviation being 0.07 %.

In the second test, reactive power is produced by modulating the cosPhi setpoint on the inverter in increments of 0.1. It be noted that a positive value for cosPhi is considered to be a leading cosPhi, and therefore, the inverter is generating reactive power. As can be seen in Figure 8, the active power generation is fairly steady throughout the test, although minor changes in active power production cause the inverter to vary the reactive power output to maintain the cosPhi setpoint. As a result, the production of reactive power is not particularly smooth. Yet, the response of the inverter is almost instantaneous, with an accuracy of under 1% for the entire test (Table 4).

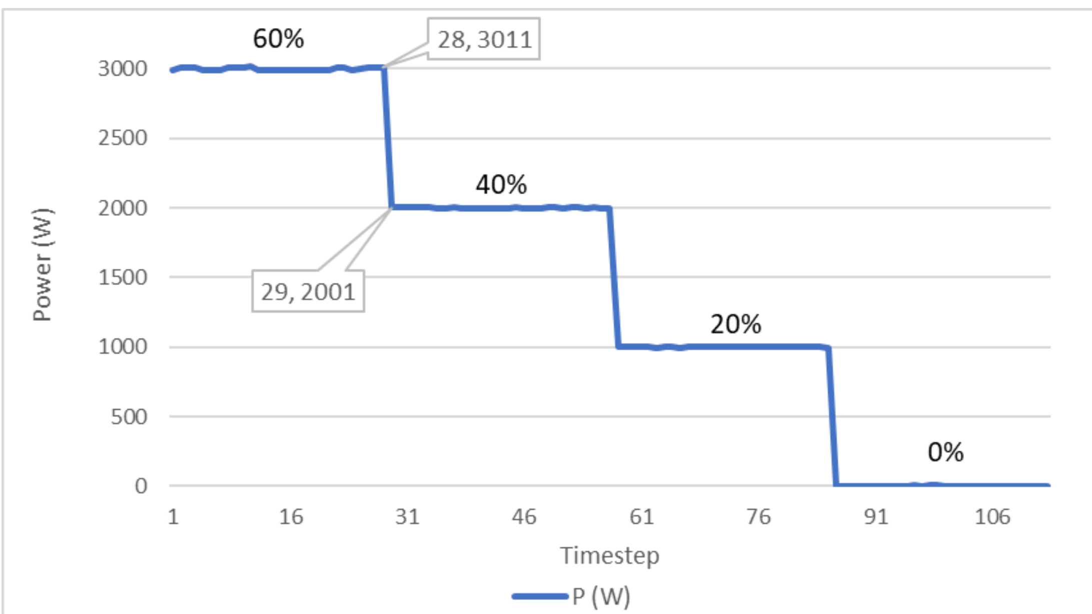

Figure 7 - Active power modulation test for the SE 5000H in steps of 20%. The inverter reacts to new setpoints within the next time step.

Curtail Setpoint (%)	Expected Power (W)	Actual Power (W)	Deviation (%)
60	3000	2997.99	0.07 %
40	2000	1999.62	0.02 %
20	1000	999.52	0.05 %
0	0	0.5	-

Table 3 - Test results for active power modulation of the SE 5000H in terms of deviation.

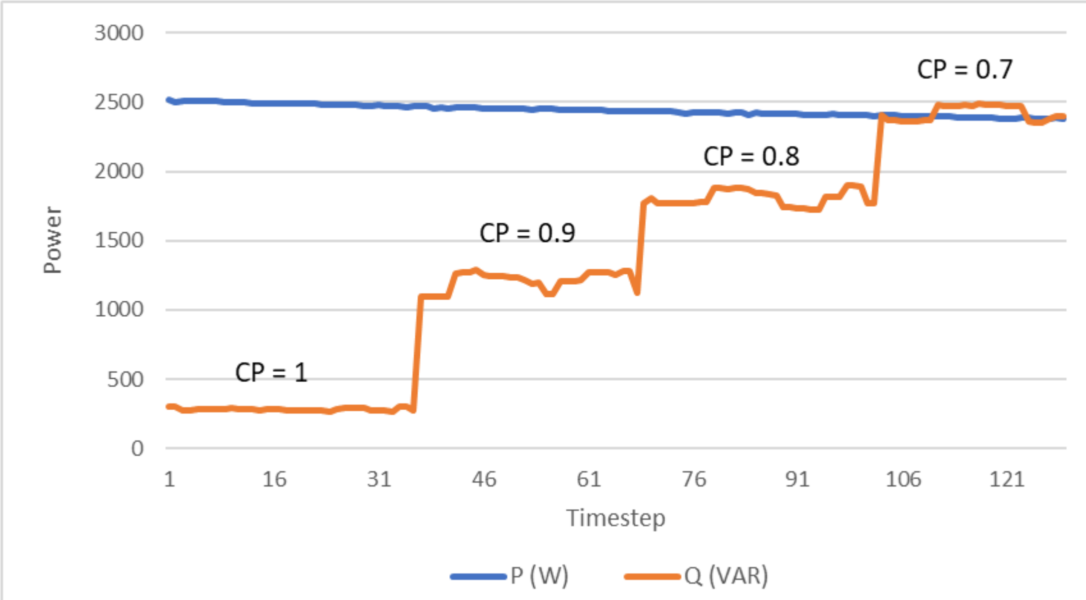

Figure 8 - Dynamic cosPhi modulation test for the SE 5000H in steps of 0.1.

cosPhi Setpoint	Actual cosPhi	Deviation (%)
1	0.9935	0.65 %
0.9	0.8965	0.39 %
0.8	0.8009	0.12 %
0.7	0.7024	0.35 %

Table 4 - Test results for cosPhi power modulation of the SE 5000H in terms of deviation.

The output of both tests confirm that the SolarEdge inverters are indeed capable of dynamically modulating active/reactive power in a very short response time.

Technical Note 1: SolarEdge inverters are capable of performing all of the functions given in Table 2, however, there are crucial architectural differences within the SolarEdge control settings that impact the response time of the inverter. SolarEdge control settings come in two flavors, dynamic and enhanced. In dynamic mode, the inverter will respond almost instantaneously to new active/reactive power setpoints but will not persist the setpoints to memory. In enhanced mode, more advanced control options such as constant reactive power, VoltVAR curves, and Volt/Watt curves can be accessed, however, each new setpoint requires a reset of the inverter settings. This procedure stops the production of active and reactive power for a period of 20-40 seconds before the new settings take effect. Considering the voltage regulation algorithms must have a fast response, the benchmarks will be restricted to testing **only the active power deration and cosPhi modulation** functions in dynamic mode.

2.3 LCSG Sensitivity Results

In designing the voltage regulation algorithms for the project, it is crucial to quantify how sensitive the voltage at the LCSG facility is to both active and reactive power injections. In other words, the amount of active power/reactive power production needed to affect the voltage at the EPC by 1 volt must be calculated. Determining these sensitivity factors will help tune the algorithm in taking precise control actions to regulate the voltage at the EPC to a certain setpoint. The method used to obtain the sensitivity factors relate to the following two equations:

$$SEN^{P} = \frac{\Delta P_{SE}}{\Delta V_{SE}} \quad (1)$$

$$SEN^{Q} = \frac{\Delta Q_{SE}}{\Delta V_{SE}} \quad (2)$$

where, ΔP_{SE} is change in the active power produced by the SolarEdge inverter, ΔQ_{SE} is the change in reactive power produced by the SolarEdge inverter, and ΔV_{SE} is the change in voltage at the EPC of the inverter and the distribution feeder.

In Figure 9, the strong correlation between voltage and active power can be seen as the active power is modulated in steps of +/- 20%. Both waveforms have very similar profiles throughout the modulation process and their amplitude is steady in between the perturbations to the system. Table 5 shows the aggregate power injection and corresponding and voltage measurement at the EPC of the inverters at each step. With the average sensitivity being 1594.86, it can be assumed that a 1-volt differential at the EPC of the SolarEdge inverters and the LCSG feeder will require a change of +/- 1595 W.

For the sensitivity test results in Figure 10, the active power of all setpoints was pre-emptively curtailed to 50% to negate the factor of variable irradiance/active power production. Similar to Figure 9, both waveforms show a strong positive correlation to each other. When the cosPhi setpoint is positive, the inverter acts as a capacitive load, generating reactive power and thus increasing the voltage at the EPC. On the other hand, the cosPhi acts as an inductive load when the cosPhi setpoint is negative and therefore reduces the voltage at the EPC. With an average sensitivity of 780.64, the initial consideration is that the distribution feeder is more sensitive to reactive power injections than active power injections. It must be noted, however, that the SolarEdge inverters used in this test cannot produce reactive power *without a base amount of active power generation*. This characteristic must be noted when designing the voltage regulation algorithms for the LCSG (see Technical Note 2).

Technical Note 2: Smart inverters have the capability to produce reactive power without a base level of active power generation, however, SolarEdge does not support this feature currently. This feature is known as “Q at night” and is useful for grid-tied inverters seeking to stabilize the grid when there is no solar irradiance available [17]. Simulation results in Section 4 assume that the inverter has Q at night capability.

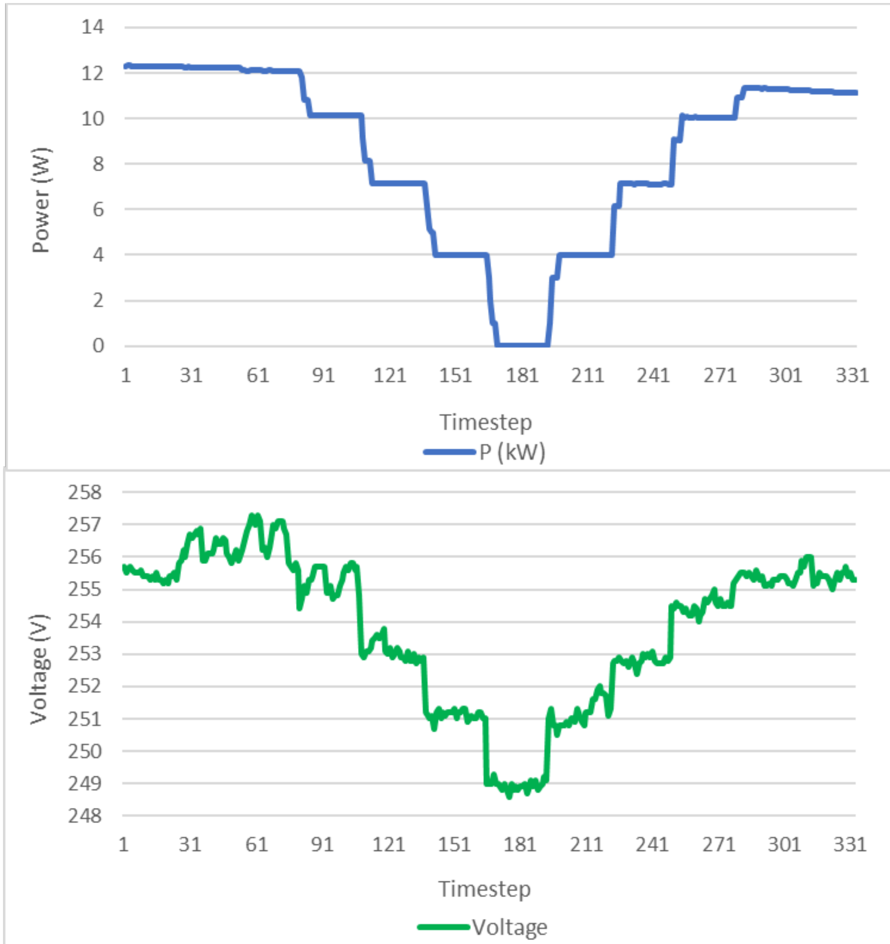

Figure 9 – Active power and corresponding voltage measurement for the SolarEdge inverters.

Curtail Setpoint (%)	Aggregate Power (W)	Average Voltage (V)	Sensitivity
60	10145.45	255.23	-
40	7140.95	253.11	1414.62
20	3999.80	251.11	1567.61
0	1.66	248.94	1847.72
20	3999.64	251.17	1791.91
40	6000	252.81	1221.46
60	8991.48	254.59	1725.84
		Average Sensitivity	**1594.86**

Table 5 - Voltage sensitivity calculations at LCSG as a function of active power.

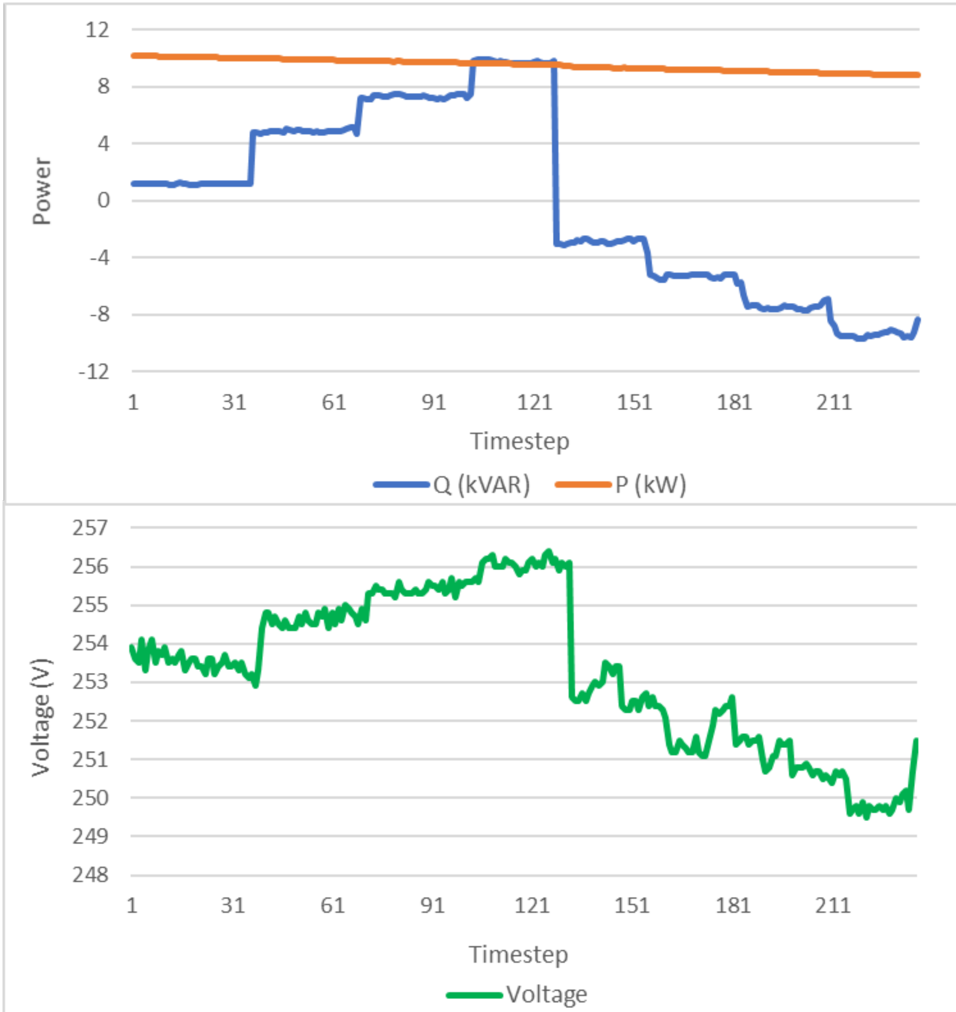

Figure 10 - Reactive power and corresponding voltage measurements for SolarEdge inverters. The active power was reduced to 50% for each inverter to mitigate the effect of varying solar irradiance.

cosPhi Setpoint	Aggregate Power (VAR)	Average Voltage (V)	Sensitivity
1	298.31	253.43	-
0.9	1216.55	254.59	788.59
0.8	1824.78	255.34	815.90
0.7	2435.37	256.01	915.46
-0.98	-533.87	252.67	-
-0.9	-1157.80	251.57	567.64
-0.8	-1719.34	250.76	695.86
-0.7	--2281.80	250.13	900.39
		Average Sensitivity	**780.64**

Table 6 - Voltage sensitivity calculations at LCSG as a function of reactive power.

3.0 COMMUNICATION FRAMEWORK

3.1 Overview of Peer to Peer Middleware

To enable communication amongst peers, P2P systems use underlying software that is known as *middleware*, which is comprised of communication interfaces and protocols that serve as a translation layer between all peers. Middleware enables each peer to access resources of another peer and exchange information within standardized formats, resulting in more flexible and interoperable systems. It follows that the concept of a peer is analogous to that of an agent, and the terms will be used interchangeably henceforth.

A standard way for agents to communicate with each other is in the form of *messages* that are meant to convey a request or a response. The category of middleware that specializes in message-based approaches is known as message-oriented middleware (MOM) [18]. One of the more popular messaging paradigms within MOMs is a publish-subscribe approach, where the information exchange between peers is facilitated by producers and consumers. Producers of data publish their messages over the network in the form of *topics* (Figure 11). Consumers of data subscribe to any interested topics and begin to receive data as requested. The middleware is responsible for the reliable transport of the message based on the subscribers' interest in relevant topics. Within this architecture, producers and consumers are decoupled from each other, leading to a more flexible and dynamic network topology. Additionally, the overall system has an increased level of scalability, since subscribers need only to declare their interest in certain topics to begin to receive data. The ability for a communication architecture to scale and support dynamic topology is of great importance to multi-agent frameworks. Especially in the context of ADNs, where potentially millions of smart devices may be integrated over the next decade.

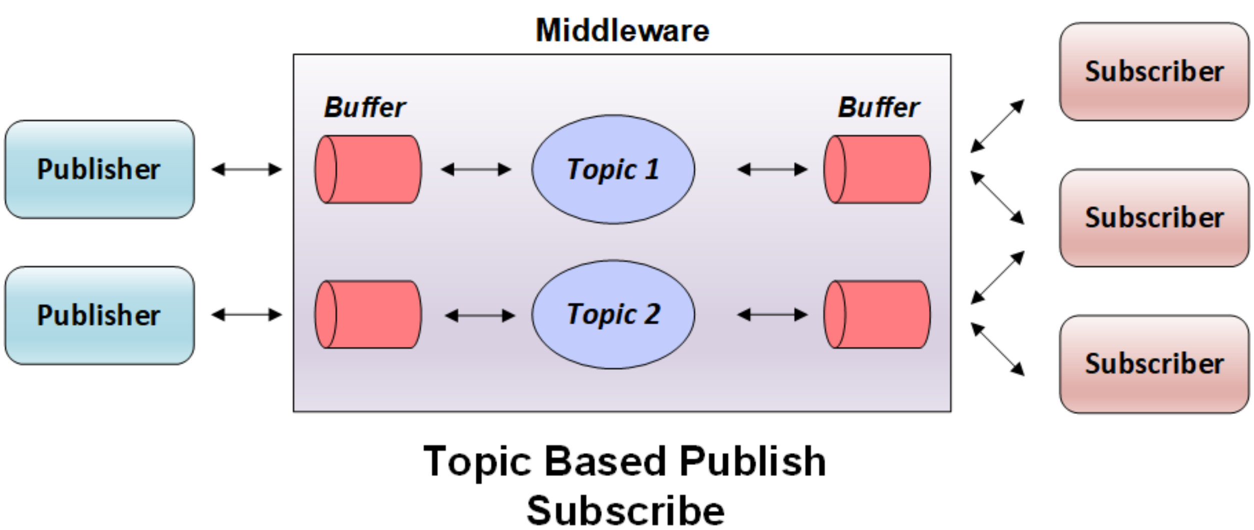

Figure 11 - Topic Based Pub/Sub Based Middleware

3.2 Introduction to DDS Middleware

Data Distribution Service (DDS) is a form of MOM that uses a topic-based, publish/subscribe approach. It has its origins in the US military, where it was mandated for use by the US Department of Defense [19]. In DDS, an overall *Global Data Space* (GDS) is defined that is shared by all network participants (Figure 12). Publishers use dynamic objects known as *DataWriters* to write data to specific topics, while Subscribers use corresponding *DataReaders* to read the data from the topic to which they are subscribed. The topics can be configured with a wide array of Quality of Service (QoS) profiles that include: message priority (more resources given to higher priority topics), reliability (defining the effort needed for message retransmission), durability (how long to store data), and deadline (setting a strict minimum publishing rate). In this way, DDS ensures that information flows directly from producer to consumer, making it a fully distributed system that is equipped to handle real-time messaging requirements.

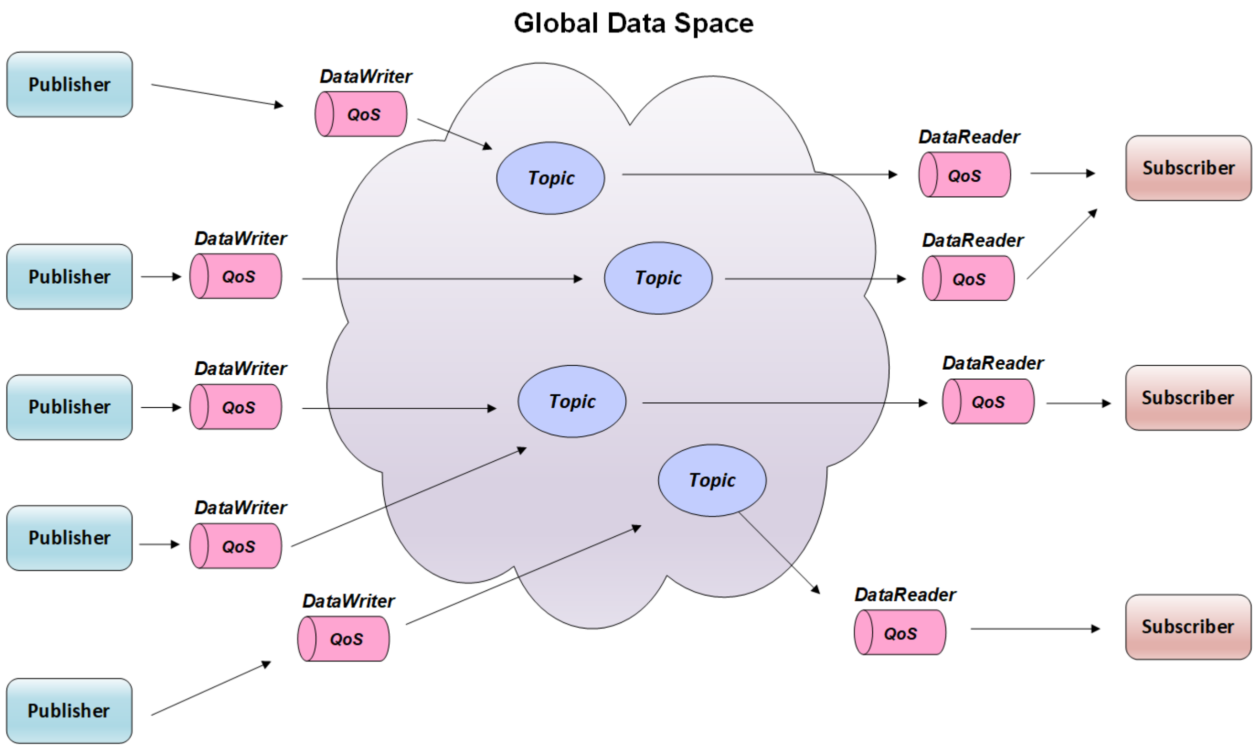

Figure 12 - Architecture of DDS

The GDS is partitioned into multiple domains, each of which hosts several domain participants that consist of publishers, subscribers, or both (Figure 13). DDS middleware facilitates the flow of information from publisher to subscriber over a real-time databus using the topic details and configured QoS profiles Any application using DDS does not need to know the network location of any other application, making it possible for DDS to "auto-discover" new publishers/subscribers and re-route information to brand new domain participants. This feature adds an extremely high level of scalability and flexibility for distributed systems.

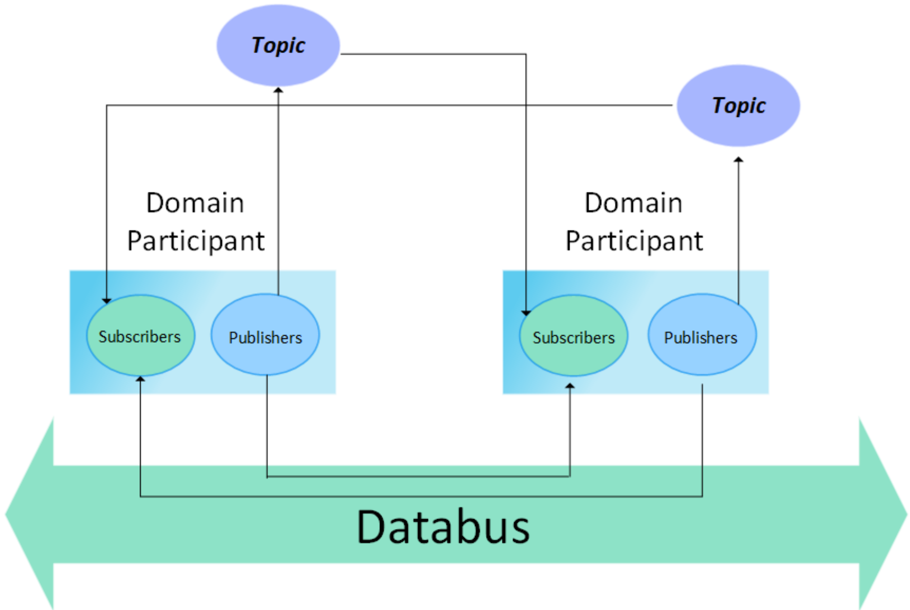

Figure 13 - DDS Domain Entities

In summary, DDS is chosen as the middleware to facilitate communication between agents because of the following reasons:

Real-Time Suitability: The usage of DDS has been proven in mission critical, real-time applications and is capable of processing millions of messages per second [20].

Fully Distributed: DDS uses a real-time, fully-distributed data bus to allow any agent to publish/subscribe data over the bus. It does not rely on centralized message brokers and does not have a single point of failure.

Dynamic Discovery: Agents are able to join and leave the network at will and immediately begin interacting with other agents by virtue of dynamic discovery. This provides the control system with a great degree of flexibility and resiliency, as "backup" agents can be brought online seamlessly in the case of a system failure of another agent.

Quality of Service (QoS): Configurable QoS parameters can be assigned to each topic to control its prioritization level, depth of reliability, as well as hard real-time constraints (among other configurable options). This allows the agents to prioritize different system elements within multi-objective control strategies.

3.3 Communication Framework for Agents

The proposed communication framework for agents is presented in (Figure 14). Each agent is a domain participant, and simultaneously publishes/subscribes to the mandatory topics within the GDS, which are noted in Table 7 below:

Agent Communication Framework		
Topic Name	**Description**	**Examples**
Services	Listing of different services agents an provide, similar to the "yellow pages" concept.	Active Power Deration cosPhi Modulation Battery Storage
AgentID	Listing of each agent ID number and the zone they control, similar to the "white pages" concept.	AgentID: 1, Zone:1 AgentID: 2, Zone:2,3,4
MsgBus	Highly prioritized topic used **only** when agents request help from another agent. Configured with additional QoS profiles of deadline and durability.	See Figure 15

Table 7 - List of Topics Within the Agent Communication Framework

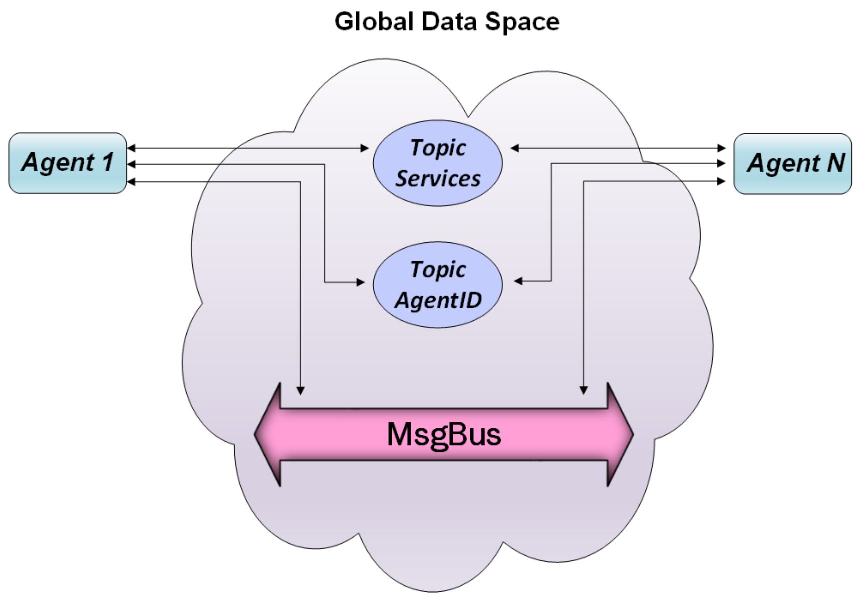

Figure 14 – The proposed architecture of the agent communication framework. Agents pass messages via the highly prioritized MsgBus to maintain a coordinated control strategy within ADNs.

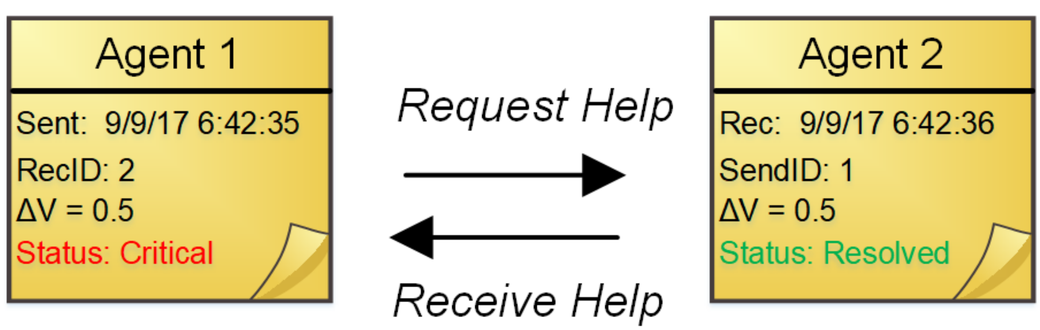

Figure 15 - An example of agent interaction. Agent 1 requests help to mitigate an overvoltage of 0.5 pu from Agent 2. Agent 2 receives and resolves the request accordingly.

With the proposed communication framework in place, agents are now able to communicate with each other via the highly prioritized MsgBus topic. This development enables the formalization of the agent-based control strategy, which will be the focus of the next chapter.

4.0 CONTROL STRATEGY

4.1 Generalized MAS Control Strategy

A general control strategy for agents at the LCSG can therefore be applied as such:

1) Any agent that does not have a zone violation becomes a *helper*. A helping agent listens for all agent messages that require help in mitigating violations and evaluates its own ability to help based on the resources it controls. The evaluation considers criteria/constraints such as feasibility, cost, and priority. If the evaluation is positive, the agent subsequently executes the control action.

2) Any agent that has a zone violation becomes a *seeker*. This agent requests neighboring agents to help it by sending requests to *helper* agents and evaluating their responses based on the same criteria as described in (1).

3) If more than one agent faces a voltage violation at the same time, the agent with the higher priority (larger violation) will take priority over the other agents.

4) Generally, it is not possible to be a helper and seeker at the same time.

The zones specified at the LCSG can be seen in Figure 16, where Agent 1 has been assigned to regulate the voltage near the Solar Building (Bus 3), while Agent 2 has been assigned to regulate the voltage near the Wind building (Bus 4). As Agent 1 has smart inverters within its zone, it has the capability to alter the voltage at its EPC by modulating active and reactive power. By contrast, Agent 2 can only be controlled to charge or discharge the battery bank or turn on the dispatchable load. DDS has been deployed over the Local Area Network (LAN) at the LCSG, thereby allowing the agents to communicate with each other over the MsgBus topic.

4.2 Distributed Voltage Regulation Algorithm

Given the capabilities of the agents, a hierarchical control strategy is proposed to mitigate voltage violations at the LCSG. The hierarchy is as follows:

1) **Local Q Control:** If the voltage falls outside of the acceptable range, command the inverters to produce the appropriate level of reactive power to bring the voltage back within range.

2) **Ask for Help:** If the required reactive power cannot be supplied, ask a neighboring agent for help. The *helping* agent will then calculate the required voltage needed at the zonal EPC and will either confirm/deny the request depending on the capabilities of the devices of its zone.

3) **P Control:** If neighboring agents fail to help, the last resort is to modulate active power. This scenario is typically seen in overvoltage scenarios, in which the agent is left with no choice but to derate its active power production to keep the voltage within range. This is the least desirable option as it leads to the significant decrease of DER asset utilization.

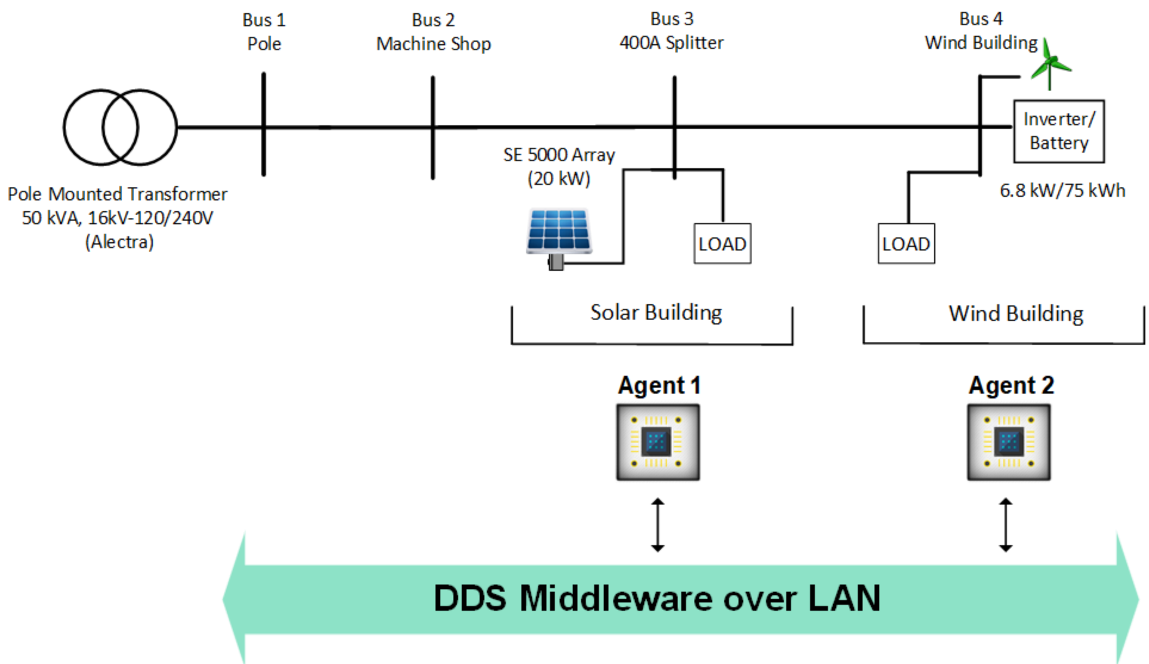

Figure 16 - Zonal Assignments of Agents within the LCSG

The above strategy can be mathematically formulated as a distributed constraint satisfaction problem (DCSP) [21]. Generally, a DCSP divides an overall system into a set of *variables* and *constraints*, where the overall aim is to assign values to each variable such that their assignment satisfies all constraints. In the context of MAS voltage regulation at the LCSG, the control variables of the agents are $\{\Delta P, \Delta Q\}$, while the constraints are the maximum power output of the inverters, as well as the state of charge (SOC) of the battery $\{P_{MAX}, Q_{MAX}, SOC\}$. The overall objective of each agent is to control $\{\Delta P, \Delta Q\}$ within its local constraints such that the zonal voltage is within acceptable limits. If a violation persists and an agent cannot find a solution locally, the agent will then ask for help from a neighboring agent, who will in turn alter *its* control variables within *its* zonal constraints. In this way, the system voltage at the LCSG can be regulated without the need of a centralized controller.

As such, the control variables for Agent 1 and Agent 2 can be formalized as below:

$$X_1 = \{\Delta P_1(t), \Delta Q_1(t)\}$$
$$X_2 = \{\Delta P_2(t)\}$$

The domain of the control variables can also be expressed by the following:

$$D_1 = \{[0..100], [-0.7..0.7]\}$$
$$D_2 = \{0,1,2\}$$

Where the first domain represents the domain values for the smart inverter (active power deration factor in terms of percentage and cosPhi, respectively). The second domain represents the domain values for the battery, which are discharging (0), charging (1), or pass through (2), wherein (2), the inverter/battery commanded by Agent 2 is simply feeding the local loads.

The constraints of the system can further be expressed as below:

$$C_1 = \{\Delta P_1(t) < P_1^{MAX}\},$$
$$\{Q_1^{MIN} \Delta Q_1(t) < Q_1^{MAX}\}$$

$$C_2 = \{SOC_2^{MIN} < SOC_2(t) < SOC_2^{MAX}\}$$

Where P_1^{MAX} and Q_1^{MAX} refer to the maximum active/reactive power rating of the smart inverters commanded by Agent 1 (5 kW and +/- 3.3 kVAR, respectively). Furthermore, SOC_2^{MIN} and SOC_2^{MAX} are the physical limits of the state of the charge of the battery commanded by Agent 2 (25% and 90%, respectively) [28]. Both agents also aim to satisfy the zonal constraint, which is the zonal voltage at the EPC.

$$C_z = \{V_z^{MIN} < V_z(t) < V_z^{MAX}\}$$

Where $V_Z(t)$ represents the zonal voltage of the agent, and V_z^{MIN} and V_z^{MAX} are 228 V and 240 V, respectively.

The search for the solution to the DSCP is launched when C_z is violated. As an example, a generalized sequence of operations is enumerated below when a voltage violation is seen by agent *i* and responded to by agent *j*:

1) Modulate reactive power capability of any available assets to bring voltage at the EPC within range. To calculate the amount of reactive power needed to bring about the desired voltage, Equation (2) is brought into the time domain and is rearranged as follows:

$$\Delta Q_i(t) = SEN_i^Q * \Delta V_i(t) \quad (3)$$

2) If the calculated reactive power is not within bounds ($Q_i^{MIN} < \Delta Q_i(t) > Q_i^{MAX}$), a constraint has been violated. Ask neighboring agent *j* for help.

3) Agent *i* sends a coded message to Agent *j*, specifying its agent ID and the desired voltage at its EPC.

4) Agent *j* calculates its ability to alter the voltage of the zonal EPC using the assets available to it. This can be done by first determining the cross-sensitivity of the zones,

$$SEN_{i,j}{}^{P} = \frac{\Delta P_j}{\Delta V_i} \tag{4}$$

$$SEN_{i,j}{}^{Q} = \frac{\Delta Q_j}{\Delta V_i} \tag{5}$$

and then using Eq (3) to determine the $\Delta Q_j(t)$ or $\Delta P_j(t)$ needed to help Agent *i* mitigate its voltage violation as below:

$$\Delta Q_j(t) = SEN_{i,j}^{Q} * \Delta V_i(t) \tag{6}$$

$$\Delta P_j(t) = SEN_{i,j}^{P} * \Delta V_i(t) \tag{7}$$

5) If the calculated $\{\Delta P_j, \Delta Q_j\}$ does not violate any local constraints (similar to Step 2), Agent *j* will confirm the message of Agent *i* and take the appropriate control action. If there is a constraint violation, it will send a rejection message to Agent *i*.

6) Agent *i* receives a rejection message from Agent *j*. As a last resort, Agent *i* seeks to modulate any active power control capability it may have using the following equation:

$$\Delta P_i(t) = SEN_{i}^{P} * \Delta V_i(t) \tag{8}$$

5.0 RESULTS

In this subsection, results for both overvoltage and undervoltage violations will be presented. The results have been obtained from two sources: simulation based and real-world implementation. For simulation results, a static model of the LCSG was developed b using real-world measurements of voltage, active/reactive power injections to approximate the impedance (resistance/reactance, R/X) of the distribution feeder. The real-world results were implemented on software controllers at the LCSG itself. It should be noted that real-world results were obtained *only* for the overvoltage violations, as the LCSG does not suffer from undervoltage.

5.1 Overvoltage Violations

5.1.1 Local Reactive Power Control

In the first set of results (Figure 17), bus 3 of the LCSG is simulated to have an overvoltage condition due to excess power production by the SolarEdge inverters. The first subplot shows the voltage at bus 3 during a typical sunny day, where the timestep of 1 corresponds to a start time of 5:00 AM, while the final timestep of 31 corresponds to an end time of 8:00 PM. The second subplot shows that Agent 1 is able to regulate the voltage below the 252 V mark by using its inverters to absorb reactive power. If local Q control was not available, Agent 1 would have to derate the power of its inverters to keep the voltage under 252 V, as can be seen in the third subplot. As such, the local Q control allows the LCSG to produce 11.5 kWh more energy than if power was derated, which is a gain of 8.8%. With the average carbon emission factor of the Ontario power grid at approximately 50 g CO2 / kWh [23], this is a GHG savings of 575g.

The real-world results for Local Q control can be seen in Figure 18, where each timestep is approximately 5 seconds in duration. As in the first simulation, the voltage at bus 3 is never allowed to exceed the 252 V threshold, despite the increasing active power generation shown in the third subplot. The agent modulates the reactive power output of the inverters appropriately, increasing the absorption rate when the voltage creeps towards the 252 V mark. With the inverter response being almost instantaneous, local Q control proves to be an effective method of regulating voltage in order to maximize active power production.

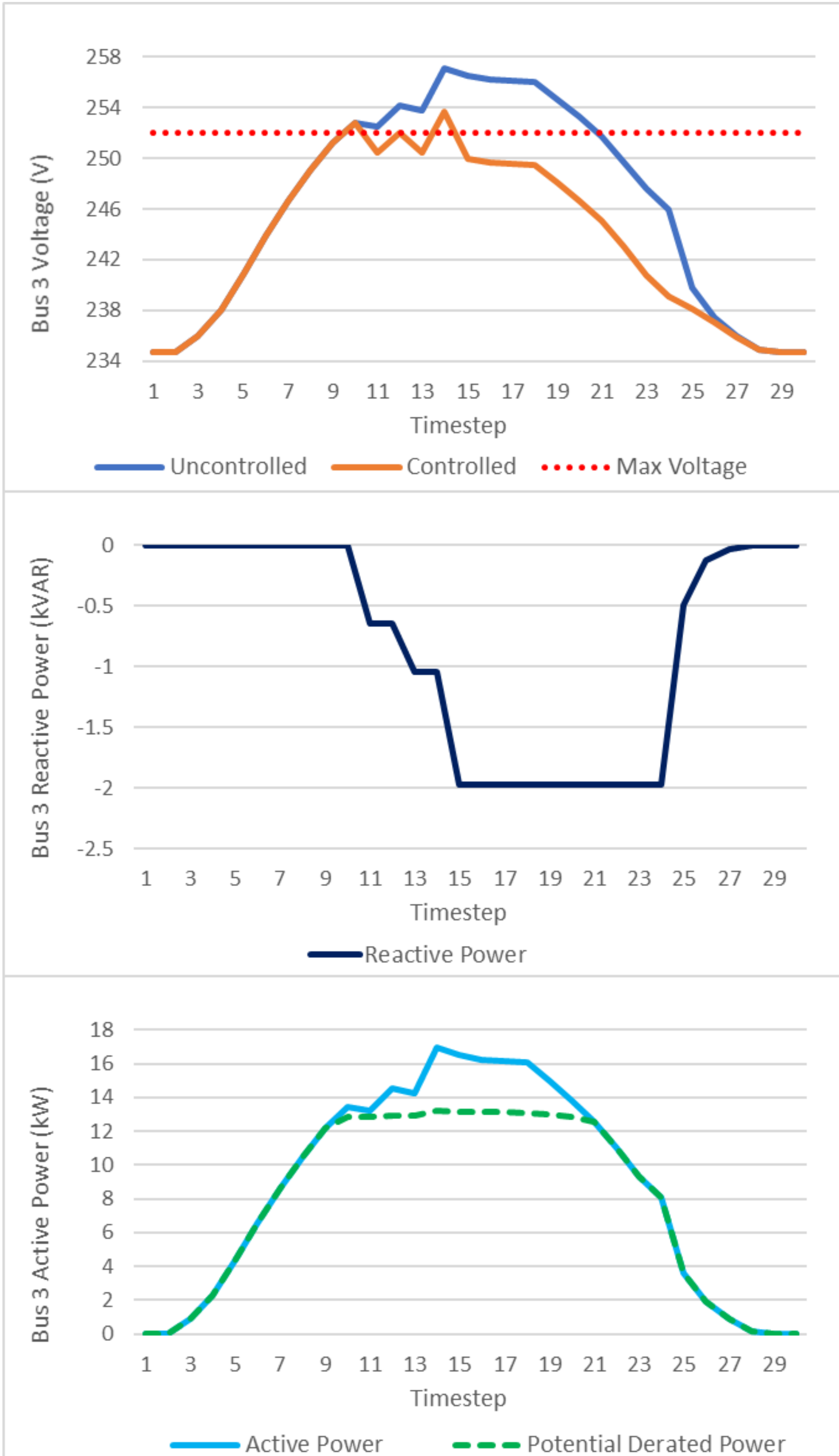

Figure 17 - Plots of voltage, reactive power, and active power during Local Q Control simulation. The absorption of reactive power from the inverters lowers the voltage within an acceptable range and allows maximum active power to be harvested during the day.

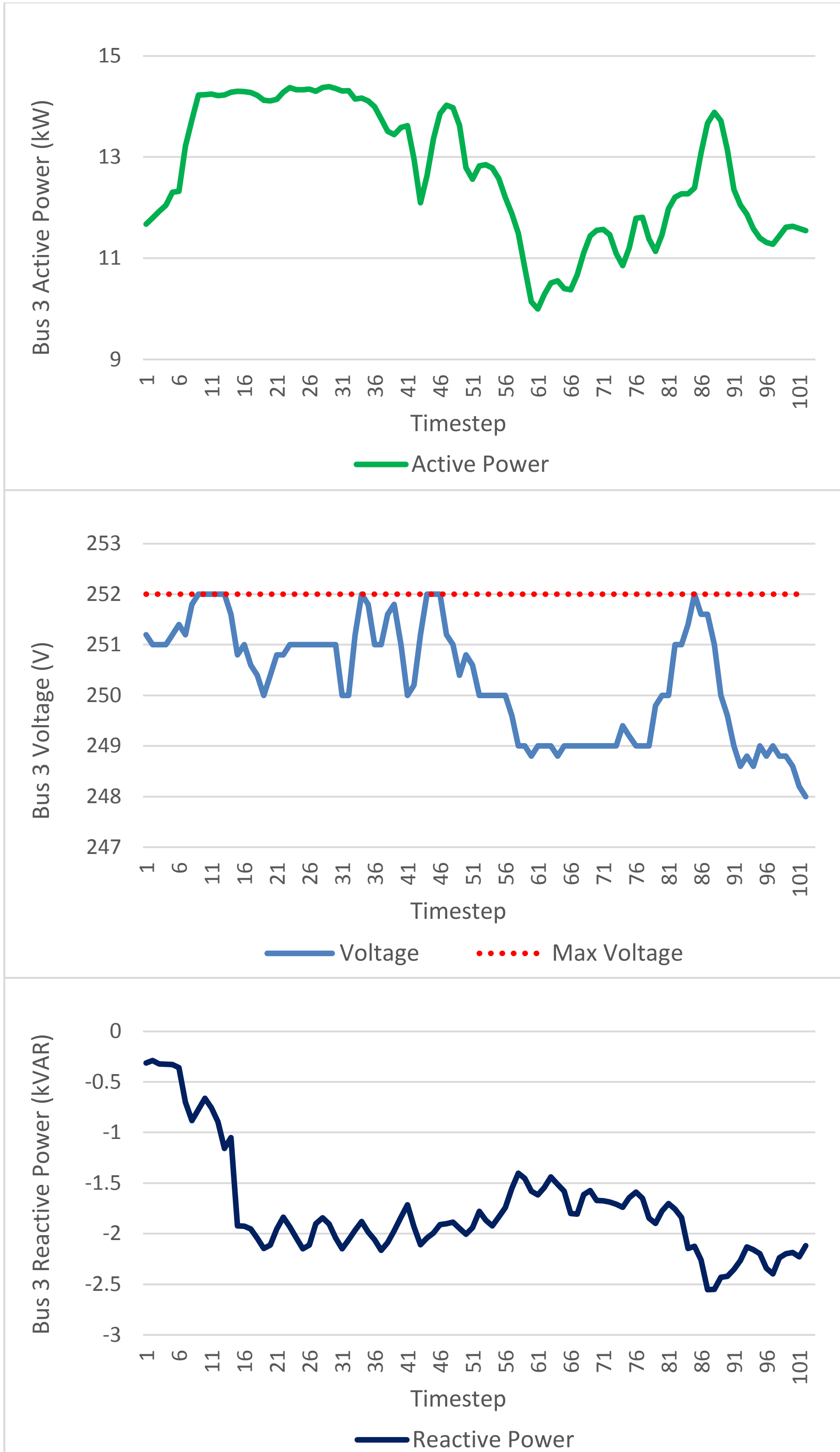

Figure 18 - Plots of voltage, reactive, and active power from a real-world implementation at the LCSG. Local agent control results in the voltage not exceeding the 252 V threshold despite increasing active power generation.

5.1.2 Agent Cooperation

For this set of results, a large reactive load is assumed to be placed within the zone of Agent 1, which prevents the agent from using local Q control to bring the voltage back within range. As a result, it must request Agent 2 for help. This can be seen in the real-world implementation result of Figure 19, where the first subplot shows two instances of overvoltage at Bus 3 (timesteps 52 and 124). In this controlled experiment, an electric heater of 5 kW was used by Agent 2 in lieu of the battery due to the unavailability of the unit. Agent 2 receives the request to help Agent 1 within 100 ms via the MsgBus and brings the load online, resulting in the mitigation of the overvoltage violation. To verify the power flow throughout the LCSG, measurements from the machine shop PQM are shown in the second subplot of Figure 18, along with the power output of Bus 3. It can be seen that irrespective of steady power production at Bus 3, the machine shop sees a drop of approximately 5 kW during the time Agent 2 turns on the 5-kW load. This control action allows Agent 2 to harvest maximum power production from its solar inverters.

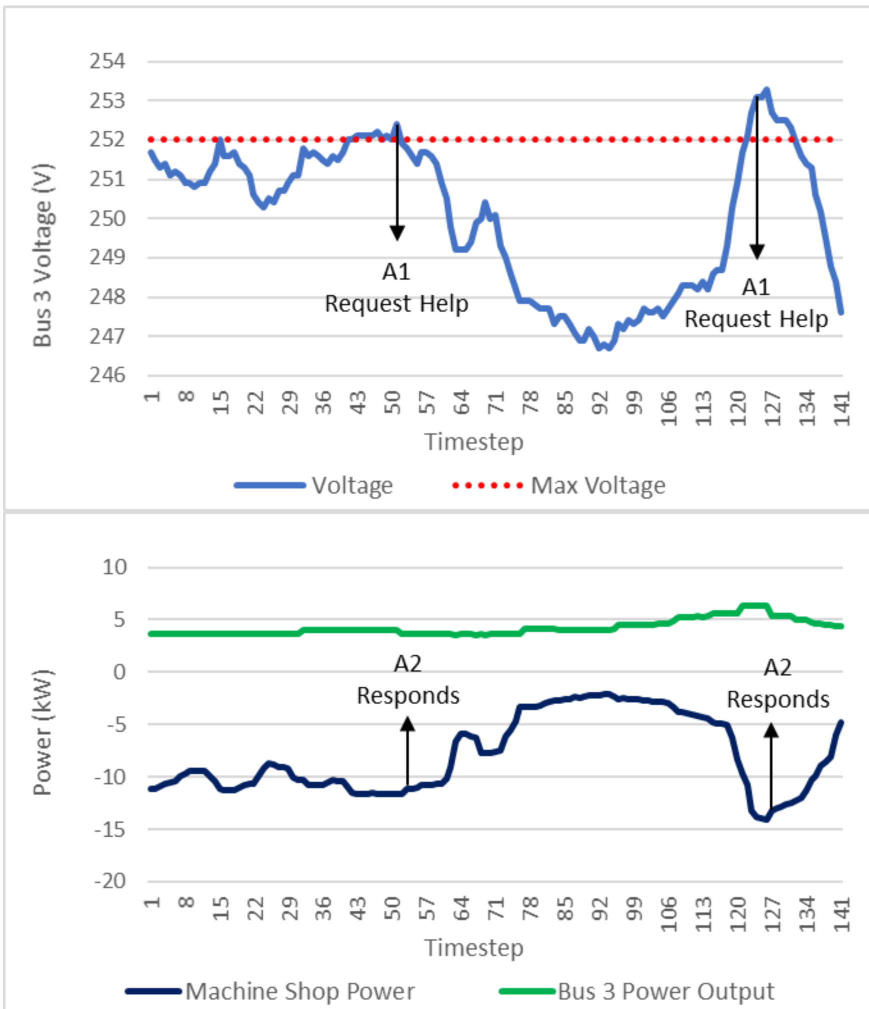

Figure 19 – Agent 2 is able to help Agent 1 mitigate overvoltage violations at bus 3 by bringing a 5W load online. Agent 1 continues to produce steady amount of active power.

In a similar *simulated* experiment, Agent 2 agrees to help Agent 1 by charging its battery to store the excessive active power generation of the solar inverters (Figure 20). At timestep 12, Agent 1 observes an overvoltage of approximately 254V, and immediately sends a request for help to Agent 2. Agent 2 receives the message at the next timestep, and calculates the total power needed to bring the voltage of bus 3 down to 251 V using Equation (7), which is approximately 2.22 V. As such, Agent 2 sends back a confirmation message to Agent 1 and sets the control mode of the battery to charge. This is reflected in the second subplot of Figure 22, where the base load of bus 4 increases from 1.5 kW to 3.77 kW. However, the battery is only able to charge for 1 timestep before reaching its maximum SOC, and therefore must stop charging the battery. Given this, Agent 1 resorts to derating the active power production of its inverters to remain under the voltage limit.

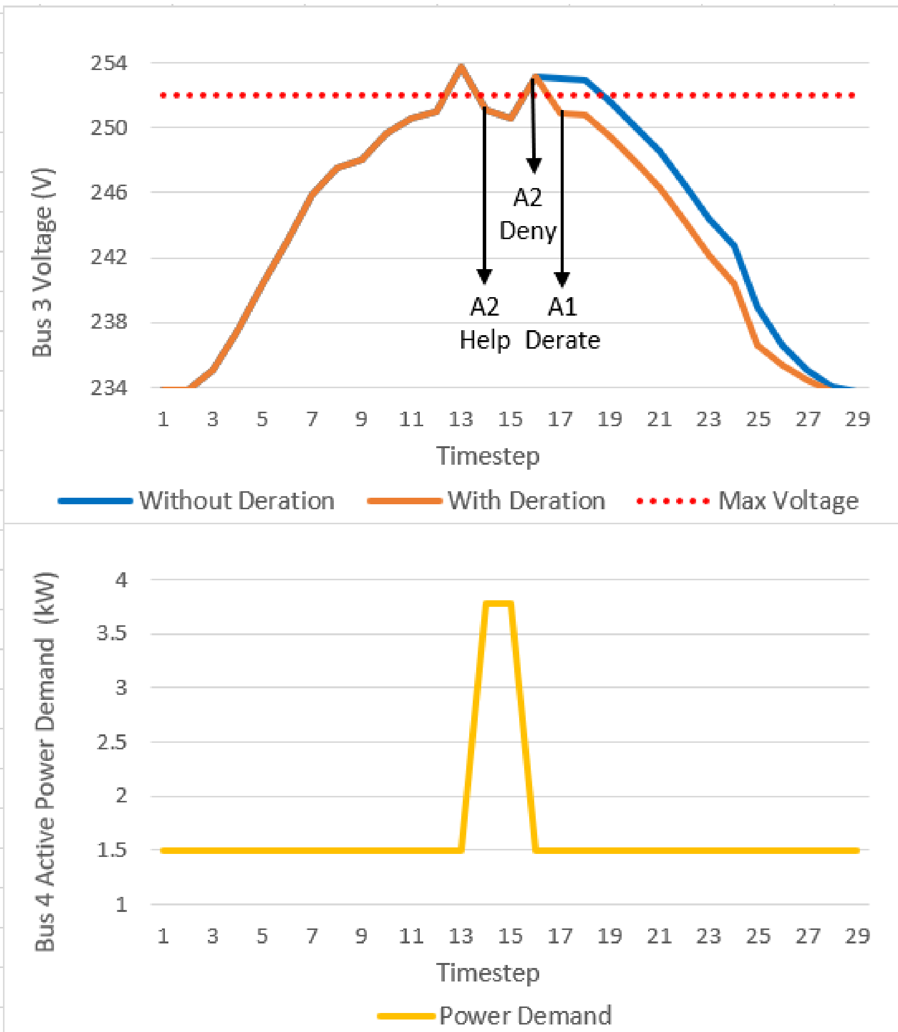

Figure 20 – Agent 1 requests Agent 2 for assistance in mitigating an overvoltage violation. Agent 2 responds by charging its battery bank briefly but must deny further requests when the battery has charged fully. Agent 1 resorts to derating the active power of its inverters.

5.2 Undervoltage Violations

In this experiment, the LCSG is simulated to have severe undervoltage violations by minimizing the active power generation in the facility (zero generation), as well as adding significant loading at all busses. The first subplot in Figure 21 shows the load profile at bus 4 during an extremely cloudy day, where the timestep of 1 corresponds to a start time of 12:00 AM, while the final timestep of 48 corresponds to 12:00 AM of the following day. The impact of the heavy loading at the LCSG can be seen in the second subplot, where the voltage at bus 4 is under the minimum threshold for over 11 hours. In the controlled simulation result, Agent 2 asks Agent 1 for help repeatedly, where Agent 1 promptly responds with calculated reactive power injections to keep the voltage at bus 4 within range. The control actions can be seen in the third subplot, where the peaks of the reactive power injection waveform coincide with the troughs of the voltage waveform (at timesteps 16, 20, 35, and 40). It can also be seen that between timesteps 20 and 34, the load at bus 3 reduces considerably. Agent 1 reacts appropriately by slowly decreasing its quantity of reactive injections to avoid unnecessary wastage of reactive power.

In the subsequent experiment, the undervoltage violation is applied to bus 3 instead of bus 4 (Figure 22). It is assumed, similar to the simulated experiment in the overvoltage scenario, that the inverters at bus 3 cannot supply the requisite amount of reactive power support due to local reactive power demand. As such, Agent 1 discovers the undervoltage violation at timestep 16 and asks Agent 2 for help. Agent 2 promptly discharges its battery bank to bring the voltage of bus 3 back to acceptable limits. However, the battery bank reaches its minimum point at timestep 40, and Agent 2 stops the discharging of the battery, while also denying any future requests for help. With no solar irradiance available, Agent 4 suffers through the undervoltage until the local load decreases at timestep 46. In future work, the control strategy could be augmented with an emergency load shedding step to mitigate the undervoltage situation instead of suffering through it.

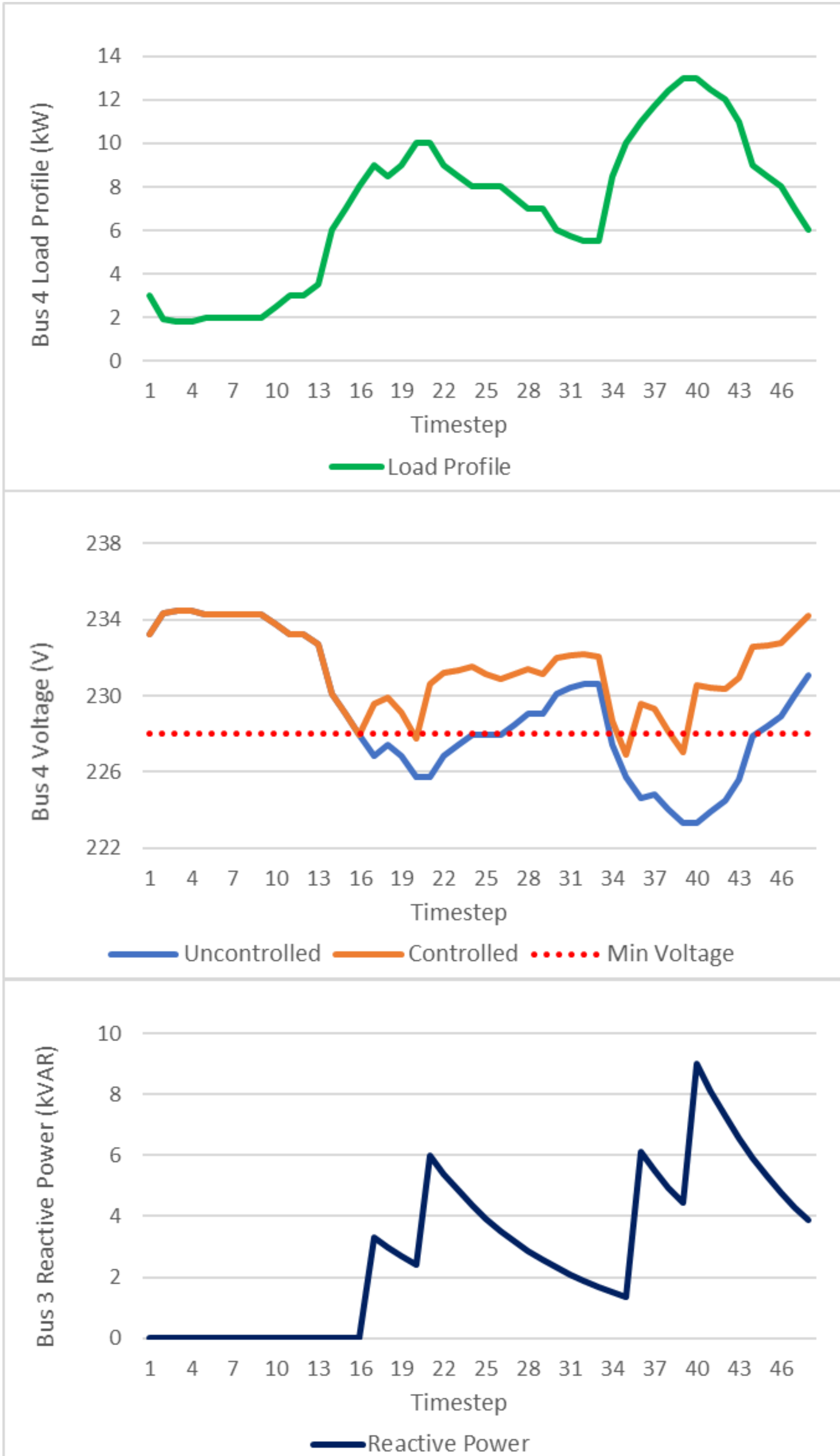

Figure 21 - Agent 2 suffers from a undervoltage violation and requests support from Agent 1, which responds with reactive power injections to stabilize the voltage at bus 4.

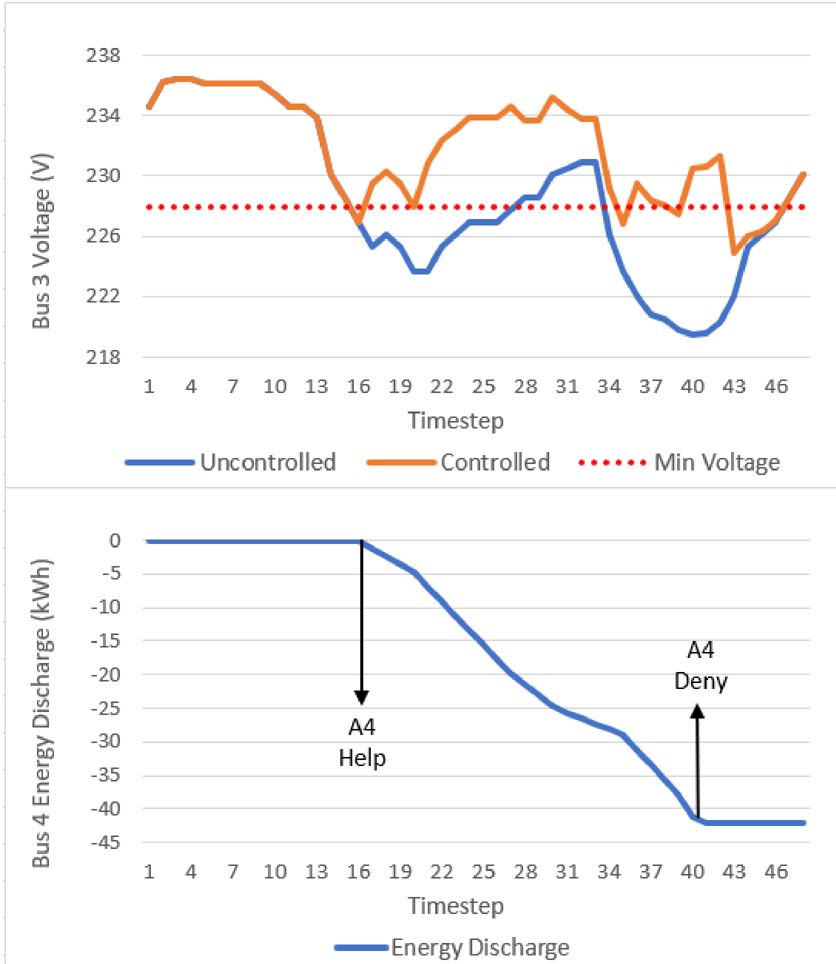

Figure 22 - Agent 2 discharges its battery bank in response to an undervoltage violation as seen by Agent 1. The battery discharges until it reaches its minimum SOC and denies any subsequent requests for help.

6.0 UTILITY COMMUNICATION AND CONTROL

This chapter section focuses on the utility remote control portion of the project. This control mode is particularly useful for utilities that may require emergency grid support at various points within an electrical distribution network, thereby commanding distributed agents to inject/absorb reactive power, curtail active power generation, or disconnect from the grid entirely. The protocols that are used to facilitate the communication between utility control centers and local agents are derived from the IEC 61850-90-7 standard.

6.1 Overview of IEC 61850-90-7

One of the main concerns addressed by this standard is the lack of cohesion between power/utility system operators and individual DER units. Given the limitations of legacy SCADA power systems, a centralized approach is impractical with the penetration of DERs, which may extend to thousands and millions of individual units in the near future. As such, this standard proposes the integration of DER Management System (DERMS) software to act as an intermediary between utility systems and DER units. Control requests can be sent to the DERMS from the power system operator, which will assess the request and translate it into specific functions that the DER units can perform. This scheme provides levels of abstraction between the utility and the DER units, as the utility does not need to know the specific capabilities of the DERs in the field. Instead of communicating with potentially millions of devices, the utility needs to communicate only with several DERMS' that would be spread over large spatial areas. The communication scheme is presented in the standard as a three-tier communication architecture in Figure 23, while a description for each level is given below.

Level 3: Broadcast/Multicast – At this level, the power system operator can broadcast control requests to a wide array of DERs. The control request is interpreted by the DERMS, which in turn, commands the DER units in its jurisdiction appropriately. Several use cases for broadcast signals are for pricing signals, ancillary grid support requests (VAR compensation, power factor correction), or demand response. The broadcast signal is usually used for one-way communication and is an efficient way to disseminate information to a large number of subscribers. Information exchanges at this level are on the order of minutes to hours.

Level 2: Local DERMS – Local DERMS receive general control requests from power system operators and translate the request into a specific set of actions that are compatible with the individual DER units in their jurisdiction. This translation requires the local DERMS to know the topology of the local power system and the capabilities of each DER unit. The DERMS is also responsible for the monitoring of the DER units, and submitting aggregate information (voltage profiles, line loading etc) to the utility on request. Information exchanges at this level are on the order of seconds to minutes.

Level 1: Autonomous DERs – These inverter-based DER units are highly dynamic, able to sense local conditions (voltage, frequency) and respond to any abnormality on a cycle to cycle basis. The inverter executes pre-configured control settings that are stored within its local memory and respond to the supervisory setpoints that are set by the DERMS via the power system operator.

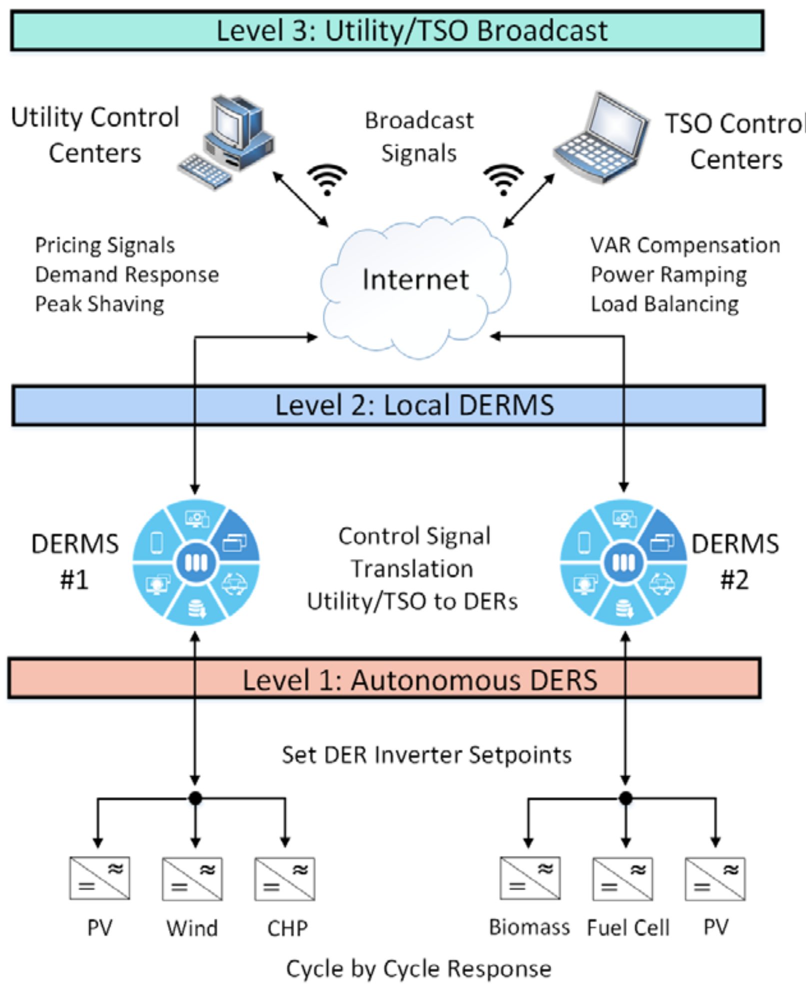

Figure 23 - Utility/DER Communication Architecture

6.2 Multi-Agent Control of Smart Inverters and other Devices

Although the control hierarchy is well defined in the standard, the decisive question remains as to which entity is responsible for setting the setpoints on these devices, particularly for situations where dynamic control is required? It is impractical for a utility control center to continuously update the setpoints for potentially millions of devices in the field. The local DERMS is a better candidate because of its proximity to the device, yet most DERMS' are still centralized and vulnerable to the same issues. The crucial point is that local optimization and dynamic control in power systems is severely limited if a device must continuously rely on an external entity to update its configuration settings, particularly in situations where fast decisions must be taken.

In combining the multi-agent approach with external supervisory support from control centers and/or the DERMS, a hybrid control and communications framework can be realized that responds effectively to local, transient situations, while also providing auxiliary grid support services within the broader power system. Such a framework is imminently scalable, flexible, and interoperable, allowing devices of all types to communicate harmoniously together to achieve a common goal. By empowering local devices with intelligent capability, the overall power system gains an extra layer of resilience if communication links are severed from supervisory systems. The combination of all these factors can potentially lead to a power system that can accept a wider penetration of renewable DERs.

Figure 24 shows the proposed hybrid control/communication framework (CCF) and its chain of command. The hierarchy has been augmented with the addition of local agents between the DERMS and local devices, thereby providing another layer of abstraction between the local devices and supervisory controllers. This is useful because the control center and DERMS no longer need to know specific, minute details about all deployed devices within the field, which significantly reduces system latency and complexity. All control requests from the power system operator are facilitated by the Manufacturing Message Specification (MMS) communication protocol, which is supported by IEC 61850 [23]. The DERMS will then map the control signals from MMS to DDS topics, from which the agents can begin to execute the command. The mapping process is typically known as *protocol conversion*, and is a crucial factor in power systems interoperability

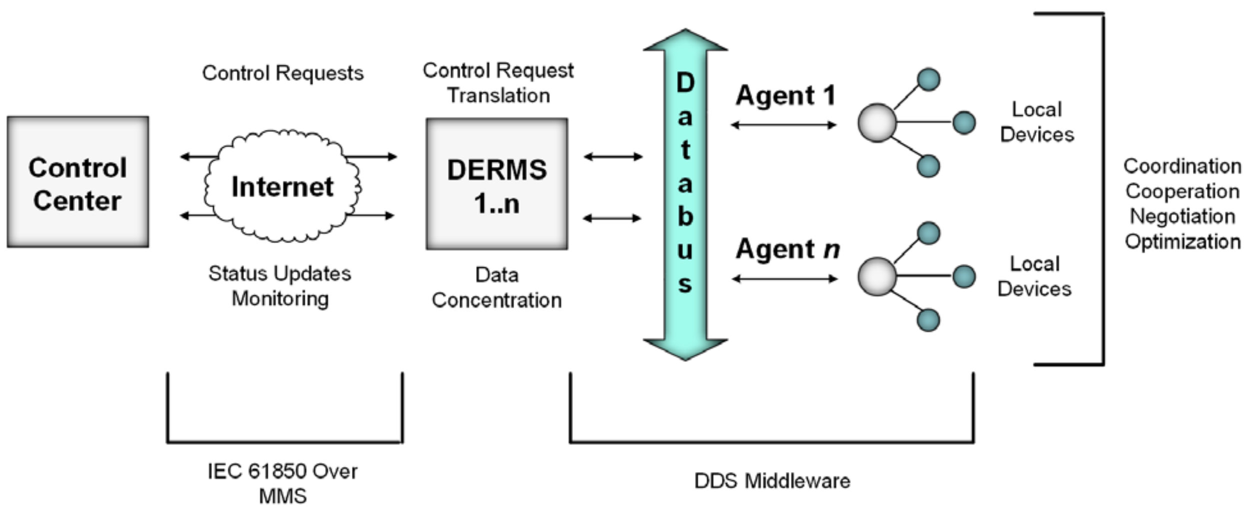

Figure 24 - End to End Control/Communication Framework

The agents are also responsible for sending status updates and measurements to the DERMS, which concentrates the data and sends it back to the control center. It must be noted that the DERMS can also be represented as another agent, since it will play a role in the coordination of distributed control schemes. However, due to its ability to understand and facilitate utility requests, it can be denoted as the **ancillary agent**. An implementation of the proposed control hierarchy at the LCSG is shown in Figure 25, where the grid operator can remotely control the LCSG over a virtual private network (VPN).

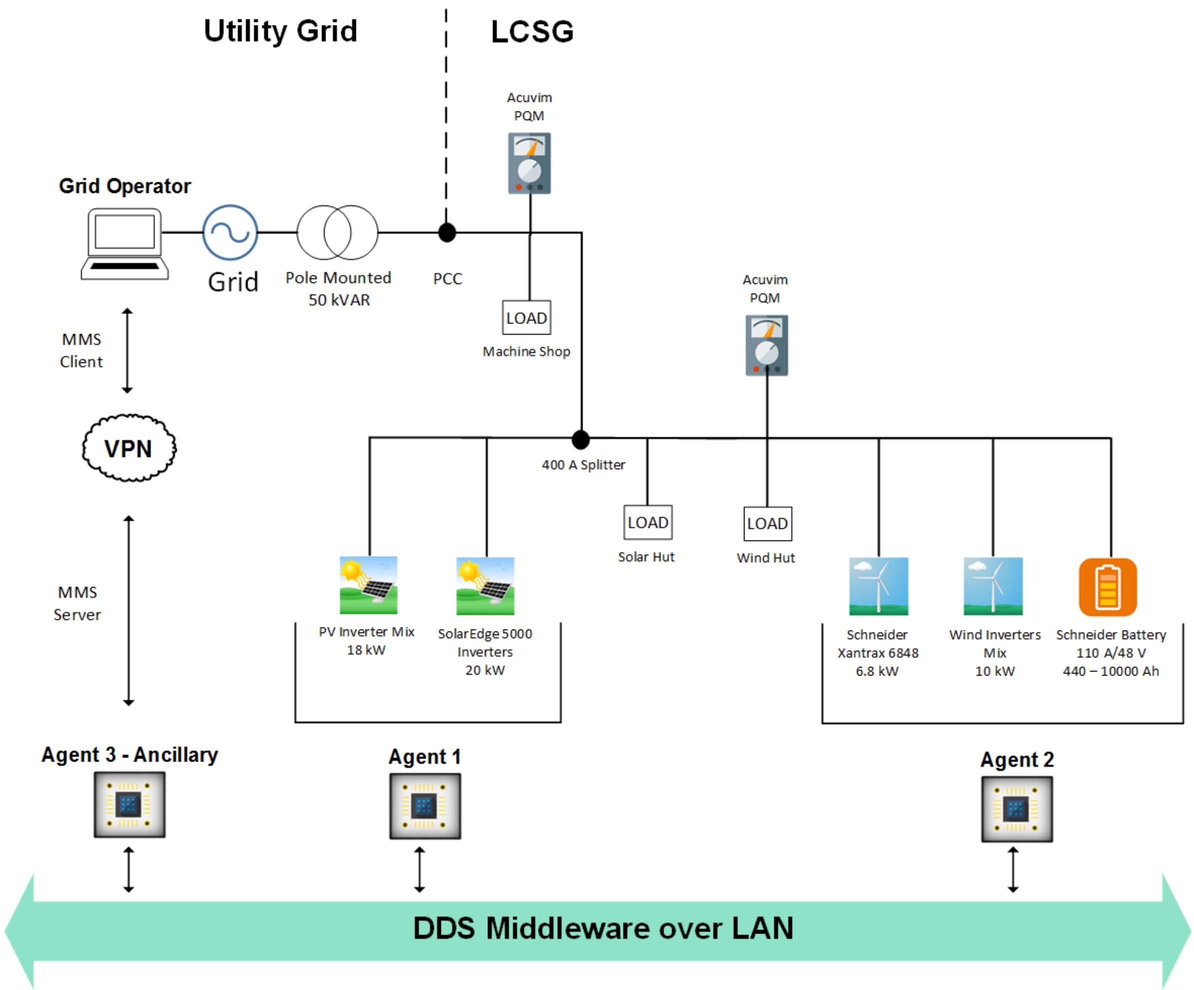

Figure 25 - LCSG Control/Communication Framework

6.3 Utility Control Center Software

For this project, a utility control center software (UCCS) has been developed that enables two-way communication between a utility control center and their DERs via ancillary agents. The user interface for the UCCS is shown in Figure 26, where operators can send general/specific power requests and visualize monitoring points throughout the grid in real-time. General requests can be made by an operator that sees a disturbance or suboptimal performance in a particular area of their network and may not know the capabilities of the DERs within the area. In this case, a general request would be sent to the ancillary agent of that area, which would then oversee its implementation in conjunction with its agents. Specific requests typically would have additional parameters associated with it, such as a target power factor, or the connection/disconnection of all DER assets from the main grid.

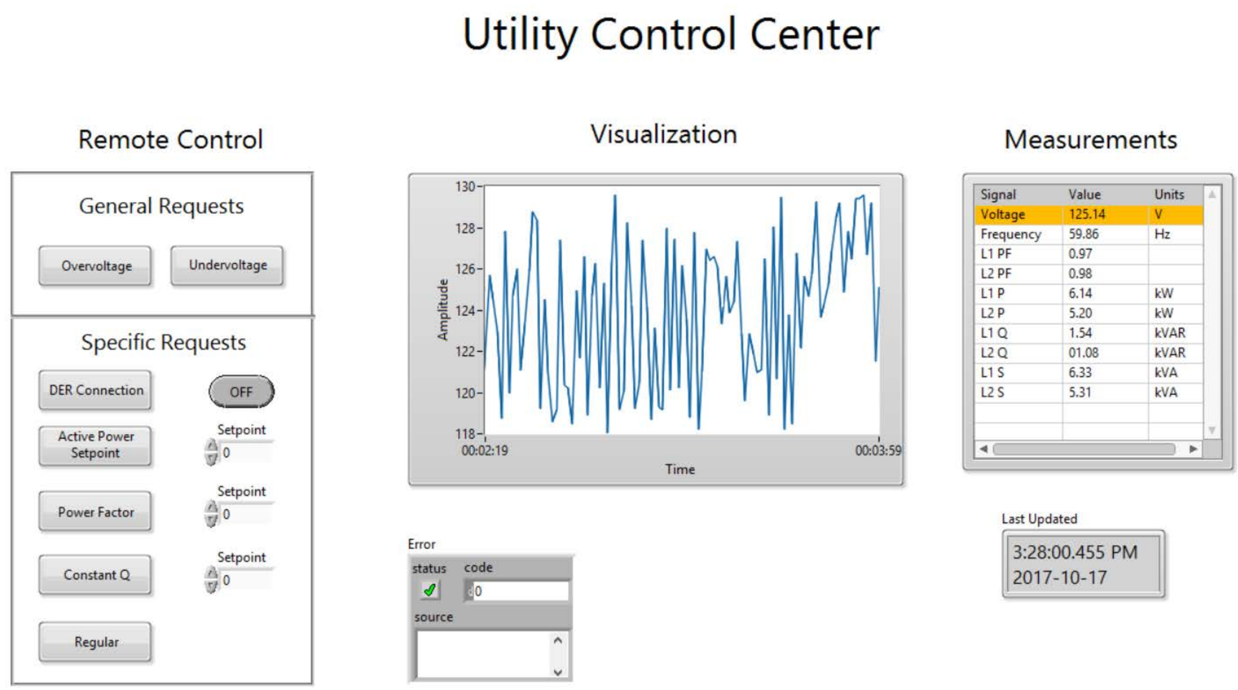

Figure 26 – The user interface for the UCCS. Power system operators can send emergency requests to distributed grid assets and visualize various monitoring points throughout the grid.

The real-world implementation of the UCCS was tested with LCSG agents to demonstrate a proof-of-concept for the overall communication/control architecture proposed in Figure 24. For the experimental setup, the UCCS was running on a Windows based computer, and connected to the LCSG network via a Virtual Private Network (VPN). The agents were running on various hosts at the LCSG network. Due to the UCCS client being connected to the LCSG network via VPN, the facilitation of the request was instantaneous. However, it is expected that if the utility software is moved to a network which utilizes 3G or WiMax technology, the transmission time would be more than 2 seconds, as is standard for utility control center to substation communication at present day [4].

Results of two specific utility requests are shown in Figure 26 and Figure 27. In the first request, the utility requests maximum reactive power injection by the LCSG at time step 2, which is immediately received by the ancillary agent and published to the local agents. The local agents then set a reactive power set point of +3.3 kVAR on the SolarEdge inverters. The inverters receive the updated setpoint, perform a configuration reset (discussed in Technical Note 1), and ramp to the desired setpoint. When the setpoint has been achieved, the measurement of reactive power at the PCC was 11.83 kVAR, resulting in a net injection of 12.97 kVAR injection.

In the second experiment, the utility requests a remote disconnection of all DER assets. This can be seen in Figure 27, where the control signal is received at timestep 30 and is immediately executed within the next timestep. For active power curtailment, the SolarEdge inverters do not require a configuration reset, and therefore the execution of the utility request is instantaneous.

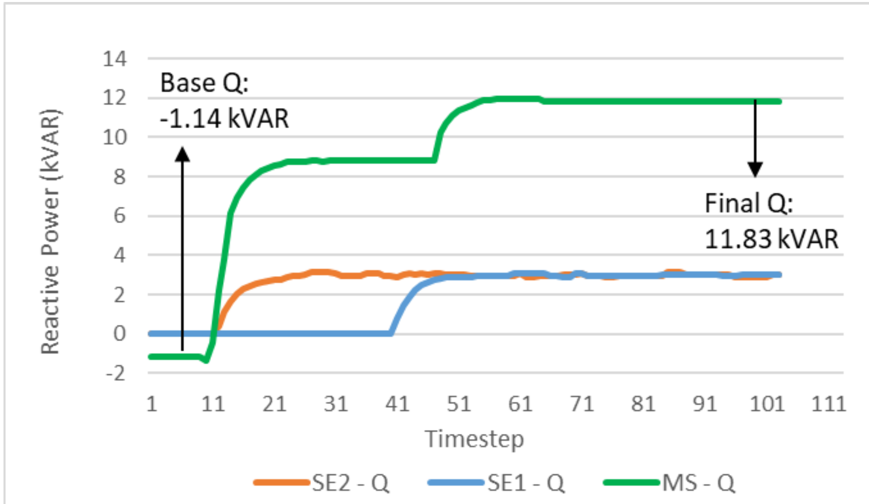

Figure 27 – LCSG Agents respond to utility request for reactive power injection by commanding its smart inverters to output maximum reactive power.

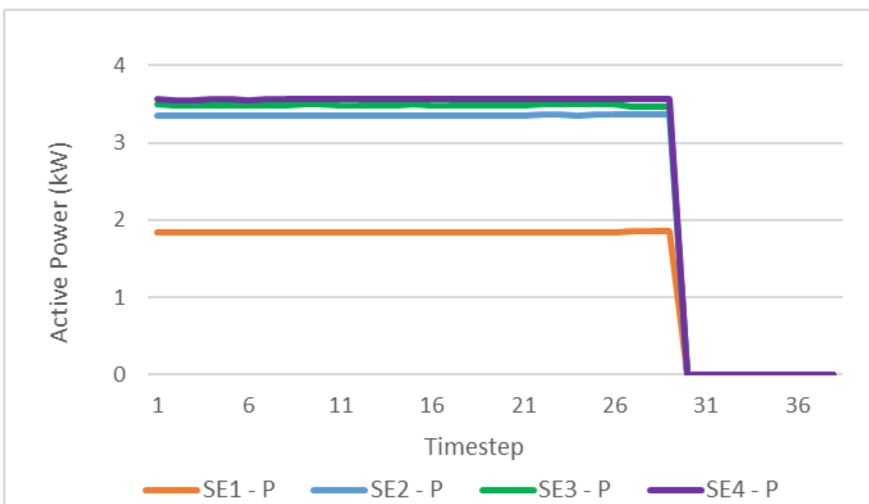

Figure 28 - LCSG Agents respond to utility request for immediate active power curtailment instantaneously.

7.0 CONCLUSION

7.1 Summary of Findings

The implementation of agent based, distributed voltage regulation algorithms at the LCSG shows great promise in the context of overall power system control. Simulation and real-world results show that agents are able to work together cohesively in mitigating both overvoltage and undervoltage violation using their combined active/reactive power control capability. In overvoltage situations, agents seek to absorb reactive power from the grid to lower the voltage, thereby allowing maximum active power generation to be harvested by DG units. This results in higher penetration of renewable energy to the grid (almost 9%), as well as increased greenhouse gas (GHG) emission savings (over 520g CO_2e daily). In undervoltage situations, a combination of reactive power injections and battery bank discharges help stabilize the voltage, providing much needed resiliency to the grid.

The communication framework used by the agents is also shown to be completely interoperable by enforcing the use of strictly open communication frameworks (DDS) as well as adhering to proper communication standards (SunSpec, International Electrotechnical Commission 61850). This allows external agents to join the overall framework and participate in any ongoing control scheme, regardless of their development platform. An example of this is the implementation of the Utility Control Center Software, which can issue emergency grid support requests to ancillary agents. This form of hybrid control offers the utilities a distributed, flexible, and scalable option to remotely control an increasing level of renewable DG units for the coming future.

Finally, it is important to note that while regulatory changes such as California Rule 21 and IEEE 1547-2014 have allowed DG units to perform grid stabilization, there is still a disconnect between legacy utility control schemes and local grid assets. The work in this project can bridge this gap by empowering the grid assets with an agent-based approach to provide cohesive, harmonious control of the grid. Coupled with powerful communication middleware such as DDS, the deployment of such frameworks could help the power system be more resilient, efficient, and environmentally aware.

7.2 Future Work

It is the endeavour of the project team to pursue the full potential of both MAS voltage regulation algorithms, as well as the further development of the overall framework. A summary of four key research avenues is presented below:

Expansion of Simulation Results

Simulation results within a greater spatial area is required to explore the true impact of the proposed voltage regulation algorithms. This can be facilitated by expanding the simulations to perform voltage regulation within the IEEE 38 bus system, as well as to work with utilities to perform real-world experiments within their jurisdiction. The integration of the UCCS software in the utility control room will be particularly interesting in providing real-time visualization and control of DERs to grid operators.

Advanced Inverter Functionality

In this project, only active power deration and cosPhi modulation are used to control active/reactive power. However, advanced inverter functions such as VoltVAR, VoltWatt, and cosPhi/Watt curves are also available as control options. Integrating these functions into the proposed control strategy may result in more granular, non-linear control of voltage/frequency within the power system.

Integration of Other Smart Grid Applications

The overall communication framework and agent-based approach is not just voltage-centric. It is generalizable to other smart grid applications that could potentially include distributed electric vehicle (EV) car charging or self-healing microgrids. The lack of EV charging infrastructure is a particularly relevant problem within Ontario and is directly relatable to the proposed control strategy.

Hardware in The Loop (HIL) Simulation Platform

There is a great need to simulate large power system models to validate control algorithms. As such, the agent-based communication framework would be converted into an HIL platform that would not only test control schemes, but also examine the impact of communication failure on the overall control strategy. The communication aspect is often neglected when discussing distributed control strategies [24].

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