San Diego Gas & Electric Company

EPIC Final Report

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Administrator	**San Diego Gas & Electric Company**
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Project Name	**Distributed Control for Smart Grids**
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Attribution

This comprehensive final report documents the work done in this EPIC project.

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EXECUTIVE SUMMARY

The objective of this project was to demonstrate a prototype distribution system control capability that could manage and dispatch higher penetrations of smart devices in the distribution systems by using local control of circuits as part of a hierarchical control strategy under the distribution management system. This project was intended to help San Diego Gas & Electric Company (SDG&E) and other utilities make strategic choices concerning distributed control systems.

As the distribution system complexity increases and more intelligent electronic and power generation/conditioning devices are deployed at circuit levels, controls need to be distributed and implemented closer to the end devices. These new, fast response, control requirements result in the need for substation-to-feeder and feeder-to-feeder controls, in a truly distributed fashion.

Work on the project was divided into four main tasks. The first task involved an assessment of trends in distribution system modernization and control. A comprehensive list of distribution automation applications was compiled and eight selected for further scrutiny. To allow utilities to gauge the maturity level of their own distribution automation implementations, four different levels of functionality were defined for each of the applications.

The second task examined the requirements of the proposed advanced distributed control system. It started by contrasting the two different schools of thought in the industry on centralized versus decentralized control methodologies and then explored what additional architectural enhancements might be considered in comparison to conventional approaches. The requisite functional, technical, standards, information technologies and security requirements for the enhanced architecture were enumerated. The concept of a regionally based master controller, distinct from the traditional centralized supervisory control and data acquisition (SCADA) system, was introduced and became one of the core elements in the test system configuration. Finally, three use cases were identified that best allowed the testing and demonstration of the application, and merits of, a decentralized control approach.

The third task leveraged the earlier work to construct a test system capable of demonstrating the use cases in as realistic a fashion as possible, and to provide a platform to contrast the performance of the conventional approach to system control with that of the new approach. Rather than construct an entirely artificial test platform, the decision was made to pick two SDG&E substations that met specific requirements and model these. The selection criteria included the requirement that the two substations be electrically connected through a tie switch or breaker, and that they possess circuits with a high penetration level of Distributed Energy Resources (DERs), with lower than average reliability (system average interruption duration index (SAIDI)) and with issues related to performance and/or power quality. The resultant two-substation system was modeled using a combination of actual Intelligent Electronic Devices (IEDs), actual DERs and the remainder simulated in a real time digital simulator that allowed power hardware in the loop testing.

The final task involved conducting extensive tests on the system, beginning with factory acceptance testing and culminating with system acceptance testing and a final pre-commercial demonstration of the operation and performance of the system at SDG&E's Integrated Test Facility (ITF). The results of those tests and the comparison between the different approaches were documented and used to formulate findings and conclusions.

Conclusions and Findings:

The results provided quantifiable evidence that the distributed control of system resources could achieve benefits when compared to a conventional approach. Major benefits identified included:

- Increase the utilization and contribution of DERs
- Reduce and even prevent unintentional reverse power flow
- Produce a flatter voltage profile over the length of a circuit
- Bring voltage profiles back inside the permissible range after a system event
- Reduce system electrical losses
- Improve the power factor of a circuit
- Reduce the number of operations of controllable assets like capacitor banks, voltage regulators and load tap changers
- Dynamically adjust protection settings to increase system reliability

The tests demonstrated that the greatest benefits were obtained when the control system was able to coordinate the control of two adjacent substations and when the regionally-based master controller was controlling the system, because it provided more possibilities for system optimization.

Additional tests demonstrated that a purely substation-based control scheme was still able to provide benefit, although not to the same extent as when the master controller was present, due to the inability to coordinate and therefore optimize between the two substations.

The demonstrated benefits of the distributed control approach in the areas of DER integration, improved grid stability, reliability and power quality and better utilization of controllable assets certainly warrants additional research, as well as inclusion into the technology roadmap of any utility facing an expansion in DER and IED devices on the distribution system.

Recommendations and next steps:

The main recommendations of the project are:

- Development of a strategic plan and roadmap for incorporating distributed control architecture as part of future deployment of advanced distribution automation systems.
- To achieve distributed controls, the focus should be on identifying certain Advanced Distribution Management System (ADMS) functions, similar to the use cases explored in the project, which can be deployed in the field through substation and field controllers that are supervised and coordinated through the ADMS at the control center.
- Further investigation focused on the standardization and expansion of field area communications as a key enabler for deployment of distributed control systems in the field.

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1 INTRODUCTION

1.1 Objective

The objective of this project was to demonstrate a prototype distribution system control capability that could manage and dispatch higher penetrations of smart devices in the grid by using local control of circuits as part of a hierarchical control strategy under the distribution management system. This project was intended to help San Diego Gas & Electric Company (SDG&E) make strategic choices concerning distributed control systems.

The chosen focus of this pre-commercial demonstration project included:

- Understand preferred operational responsibilities and control characteristics of numerous distribution system resources that can be controlled by a distributed control system infrastructure.
- Develop and test methods of communicating and coordinating control across multiple resources to ensure that devices operate in a complementary manner to optimize distribution system performance.
- Identify distributed control methods and approaches to control resources and integrate as part of a unified control scheme that is compatible with other utility control systems such as Supervisory Control and Data Acquisition (SCADA), Advanced Distribution Management System (ADMS), Distributed Energy Resource Management System (DERMS) and Demand Response Management System (DRMS).
- Demonstrate distributed control concepts that fill gaps in traditional control system infrastructure, and are compatible with it.
- Assess the scalability and performance of the control schemes against distribution system optimization objectives, using metrics such as circuit electrical efficiency, stability, reliability, frequency control, voltage support, asset health maintenance, and operating costs.

1.2 Issue/problem being addressed

A multitude of new types of controllable devices are being introduced in the power distribution system. The new devices have inherent functional capabilities whose operation needs to be coordinated and managed, in coordination with the existing devices, to derive maximum value from the available functions and improve distribution system electrical efficiency, reliability, power quality and operational costs.

The utility distributed control system must be able to interact with these controllable devices, and process the large amount of system status information coming from these devices, sensors, and monitoring nodes. The distributed control system must also coordinate and dispatch these controllable devices in a strategic, fast and automated manner.

While the control of individual elements within an electric power distribution system is fairly well known, there is not a commonly-accepted model available for the control of the whole distribution system. The existing control strategies for the distribution system have been developed in the context of the 20th century circuit design, which are being widely changed for the distribution grid of the future.

For instance, distributed energy resources (DERs)[1] play a key role in industry trend, as utilities are moving towards a future where DERs penetrate the distribution system at unprecedented levels. It is worth noting that while concerns about impact of increasing level of DERs in distribution system on control and operation of the distribution system remain unanswered, interconnection policies are resolving the deployment challenges with the development of strict standards for more utility controls and interaction with DERs. Therefore, the ability to accurately determine mitigation actions and remotely control the system is gaining more attention by utilities.

1.3 Project description, tasks, and deliverables produced

This project demonstrated a distributed control system capable of utilizing both conventional and new types of actively controllable devices in the distribution system in response to dynamically changing operating conditions.

This unified control platform, referred to as the Advanced Distributed Control System (ADCS), was expected to be compatible with conventional distribution control system technologies, including DERMS, DRMS, ADMS, distribution automation and substation automation, as well as to have the ability to effectively manage and coordinate the resources and devices at the distribution substation and distribution feeder interacting with retail and third-party-owned resources, for example, aggregators.

After formation of the project team and development of the project plan, the project was executed over the four major task areas illustrated in Figure 1-1 below.

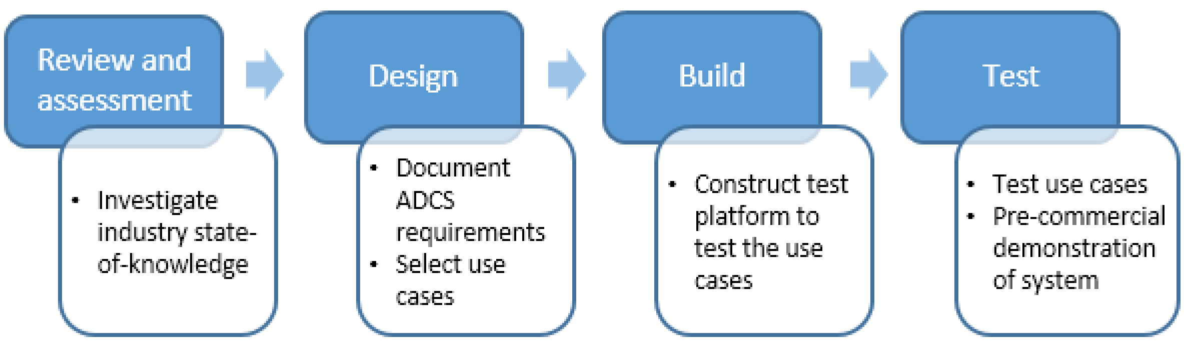


Figure 1-1. Primary project task areas

The sections that follow briefly outline the scope of work of each task and the deliverables produced.

Distributed control system review and assessment

This task documented trends in grid modernization and control based on a literature review from publicly available documents. A comprehensive list of distribution automation (DA) applications was compiled and eight selected for further scrutiny. To allow utilities to gauge the maturity level of their

[1] According to California Public Utilities Code Section 769, energy efficiency, electric vehicles, demand response, renewable resources, and energy storages are considered as distributed resources.

own DA implementations, four different levels of functionality were defined – from “Traditional” to “Trendsetter.”

Distributed control system design

This task examined the requirements of the proposed advanced Distributed Control System. It started by contrasting the two different schools of thought in the industry on centralized versus decentralized control methodologies.

As the distribution system complexity increases and more intelligent electronic and power generation/conditioning devices are deployed at circuit levels, controls need to be distributed and implemented closer to the end devices. These new, fast response, control requirements result in the need for substation-to-feeder and feeder-to-feeder controls, in a truly distributed fashion. This could ultimately include peer-to-peer communications utilizing, for example, the IEC 61850 communication standard, but that falls outside the scope of this particular project.

With this basis, the project examined what additional architectural enhancements might be considered in comparison to conventional approaches. The requisite functional, technical, standards, information technologies and security requirements for the enhanced architecture were enumerated. Finally, three use cases were identified that best allowed the testing and demonstration of the application, and merits of, a decentralized control approach.

Distributed control system test platform construction

This task leveraged the work from previous tasks to design a test system capable of demonstrating the use cases in as realistic a fashion as possible and providing a platform to contrast the performance of the conventional approach to system control with that of the new approach.

The test system was constructed using a digital system simulator and the demonstration circuits were modeled after actual SDG&E distribution circuits. The selected circuits were picked because they possessed the unique characteristics that have historically proven challenging for the integration of new distribution circuit features – including high penetration of solar photovoltaic (PV) systems, presence of sensitive loads, and customers with premium power quality requirements.

Distributed control system pre-commercial demonstration

This task created a series of factory and site acceptance test procedures intended to test the use cases on the test platform, after which the pre-commercial demonstration was performed and the results captured. The demonstration was performed on the digital system simulator in conjunction with Hardware-in-Loop (HIL) and Software-in-Loop (SIL) testing at SDG&E’s Integrated Test Facility (ITF) in Escondido, CA.

1.4 How to read this report

The table below provides a quick reference guide on the primary content areas of the report and the page number where each starts.

Table 1.1. Navigating the document

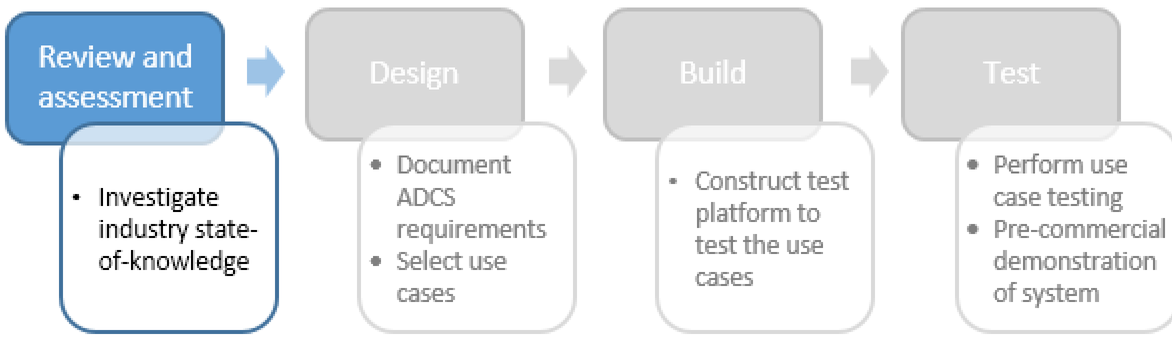
Item	Description	Starts on page
Review	**Task 1: Review and assess** Documents trends in grid modernization and control based on a literature review from publically available documents. Defines a distribution automation maturity model based on eight distribution automation applications.	5
Design	**Task 2: Design** Designs a test system and selects use cases capable of contrasting the performance of the conventional approach to system control with that of a distributed approach.	15
Build	**Task 3: Build** Creates factory and site acceptance test procedures and constructs a test system.	28
Test	**Task 4: Test** Details the test case(s) and results for each of the three use cases	42
	Findings Summarizes the results	96
	Recommendations and next steps Where to from here	99
	Appendix A – Additional use case results Provides the results for any test cases that were not described in the task 4	105

2 PROJECT APPROACH

The project started with several brainstorming sessions with stakeholders from various groups, including Growth & Technology Integration, Electric System Planning & Grid Modernization, Distribution Operations and Asset Management. These discussions were used to baseline the current state of distribution system control at SDG&E and provide a point of reference for the work that followed.

The subsections that follow provide details on the approach and results from the work performed on the four major project tasks.

2.1 Distributed control system review and assessment



The main objective of this task was to provide a summary of industry discussions and state of knowledge on advanced control and automation practices.

2.1.1 Grid modernization trends

The challenges associated with the control of the future grids as well as concerns for safe, reliable, and cost-effective operation of the grid have triggered many utilities to start planning for modernization of their electric grid. The grid modernization strategy must address challenges prompted by grid transformation drivers and take advantage of emerging opportunities. The major drivers for the grid transformation include:

- Extreme weather conditions
- Aging infrastructure/workforce
- Critical infrastructure
- Renewable surges
- Distributed energy resources

In particular, grid modernization programs should prepare the next-generation electric grid for comprehensive integration of DERs. Some of the relevant initiatives include microgrids, data analytics, smart cities, and new distribution system operator (DSO) models.

2.1.1.1 Features of a modern power distribution system

The strategy of a utility for effective operation of its power distribution system heavily depends on the changing landscape of the utility industry. Regardless, the grid modernization strategy should ensure the following feature of the electric power distribution system:[2]

- **Safety**: Grid safety minimizes exposure of personnel (crews and public) to energized equipment. In addition, potential hazards and modified operating practices caused by implementation of new technologies must be carefully studied.
- **Reliability**: Avoiding/minimizing outage times for critical/all customers is the main objective of a reliable grid design. For example, Fault Location, Isolation, and Service Restoration (FLISR) is an automation application that can reduce response time to outages. This, however, requires communication between central locations and the field in addition to new software tools that interact with field automation.
- **Resiliency**: Grid resiliency should ensure proactive/reactive response of the grid to mitigate voltage violation, system overloads, and power quality issues. It should allow for interaction with customer equipment to manage two-way power flows caused by DERs. Advanced voltage control schemes can help with realization of these goals, albeit at the cost of using automated equipment to respond more rapidly than current systems.
- **Flexibility**: Flexibility should ensure that new grid technologies can be integrated into the grid, if upgrades to existing equipment are required. For example, modular automation designs that allow for “plug and play” upgrades position the utility to keep pace with technology advancements.
- **Cost-Effectiveness**: A modern grid is not exclusively the one with best technology, but also one that is reasonable in cost for the utility’s ratepayers. It is important make investments that consider the financial needs of customers, while maximizing equipment life cycle.

2.1.1.2 Capabilities of a modern power distribution system

Several new capabilities should be developed to modernize a utility’s power distribution system. As discussed above, the goal of a modernization plan is to improve safety, reliability, and the associated cost in the electricity delivery. This is achieved by a wide range of investment in grid assets, technologies, and telecommunications overhaul upgrade.

These capabilities can be categorized into three main functionalities, namely, “Monitoring”, “Prediction and Forecasting”, and “Protection and Control.”[3] [1] A number of examples in each category are listed in the following figure.

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[2] “Grid Modernization: Modernizing SCE’s Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources,” A white paper by Southern California Edison (SCE), 2015.

[3] “Grid Modernization: Modernizing SCE’s Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources,” A white paper by Southern California Edison (SCE), 2015.

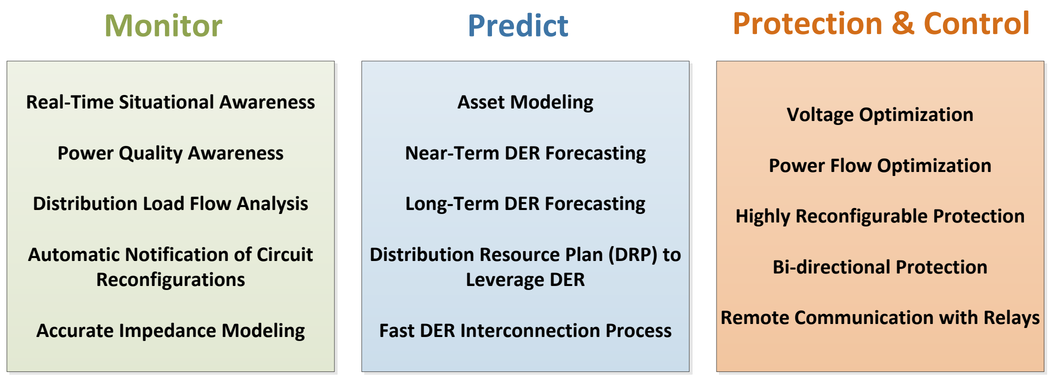


Figure 2-1. Summary of grid modernization capabilities

2.1.1.3 Grid modernization strategies

Three different business models can be envisioned for grid modernization: traditional, proactive, and aggressive.[4] [1] The selection of each business model depends on a number of external factors, including market conditions, DER adoption trends, and the regulatory policies. Further, each business model has its own set of assumptions. These assumptions are summarized in the following table.

Table 2.1. Scenario assumption in three grid modernization business models

Scenario #	Business model	Assumptions
1	Traditional	DER integration grows at a gradual rate; Undetermined policy in interaction with users and DER infrastructure; No knowledge of the technologies that will be deployed moving forward; Wider telemetry for informed decisions.
2	Proactive	DER integration grows at an increasing rate. Necessity of interaction with users and DERs in the next 10 years; Going forward with some technologies while looking forward for others to develop.
3	Aggressive	DER integration grows at a drastic rate; Regulations enforce more comprehensive interaction with users and DERs in the next 1-3 years; Utilities tend to take risks on unproven/unknown technologies.

The aforementioned future scenarios require different levels of investment – these are tabulated below. Telecommunication architecture and infrastructure, energy management solutions, and DER controls are some examples of the areas in which investments can be made.

[4] "Grid Modernization: Modernizing SCE's Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources," A white paper by Southern California Edison (SCE), 2015; "Smart Metering (SM) and Distribution Automation (DA) Program: Functional Benchmarking Report," a presentation by Booz | Allen | Hamilton (BAH) Inc., Nov. 2015.

Table 2.2. Investment measures in three grid modernization business models

Scenario #	Business model	Investments
1	Traditional	Fewer automation capabilities with telecommunication expansion; Slow energy management system modernization; Update on planning, design, and operations procedures/tools using proven technologies; No acceleration on implementation plans.
2	Proactive	Further investments on control of utility-owned assets & DERs; Modern technologies to enhance advancement of energy management systems; Additional upgrade on telecommunications infrastructure.
3	Aggressive	Grid assets modernization with a higher aggressive investment; Wide telecommunications network overhaul; Partnership with software developers to greatly scale up advanced control functions.

The associated level of risk to these three business models would vary from low to high, going from traditional approach to aggressive approach. The risk level of each modernization scenario is described in the following table.

Table 2.3. Risk levels in three grid modernization business models: traditional, proactive, and aggressive

Scenario #	Business model	Risk Level
1	Traditional	Low risk, watching to follow the winning solution; High risk of loss if DER integration accelerates.
2	Proactive	Moderate risk, the risk of stranded investment; Perhaps not prepared for emerging technology deployment, but the process can be scaled up as necessary.
3	Aggressive	High risk, the significant risk of stranded investments in modern technologies; The risk of developing advanced technologies at a higher cost.

In each future scenario, utilities will be required to adapt their resources to fulfill the requirements of the corresponding modernization plan. The resource impact is compared between the three business models in Table 2.4.

Table 2.4. Resource impact in three grid modernization business models

Scenario #	Business model	Resource Impact
1	Traditional	Using the current organizational capabilities
2	Proactive	More resources are required to manage the added advanced functionalities
3	Aggressive	Aggressive resource hiring; On-going training to keep the skill level up-to-date.

2.1.2 Distribution automation applications

Distribution Automation (DA) can be defined as "any automation used in the planning, engineering, construction, operation, and maintenance of the distribution power system, including interactions with the transmission system, DERs, and end-users."[5] A large variety of DA applications and technologies have been reported in technical literature. In general, the applications can be of either Primary type or Secondary type. Primary DA applications are those that directly benefit the performance of the SDG&E distribution system. Secondary DA applications, on the other hand, are those that support the improved performance of the SDG&E system using the data provided by the primary DA functions.

The project reviewed publicly available information to identify all potential DA applications and use cases. These were grouped into the following five categories based on their approach for improving the distribution system performance:

- Operation and Control
- Planning and Assessment
- DER Integration and Management
- Monitoring and Diagnostics
- Protection and Automation

While each application and the available technology for its implementation depends on a number of factors that will vary by utilities,[6] the aforementioned five categories represent the main types of applications identified in SDG&E. Figure 2-2 provides a shortened version of the master DA application list identified in this study.

[5] Xanthus Consulting International, "Benefit and Challenges of Distribution Automation (DA): Use Cases Scenarios and Assessment of DA Functions," A report prepared for California Energy commission, 2009.

[6] Energy & Environmental Economics Inc. and EPRI Solution Inc., "Value of Distribution Automation Applications," A report prepared for California Energy commission, 2007

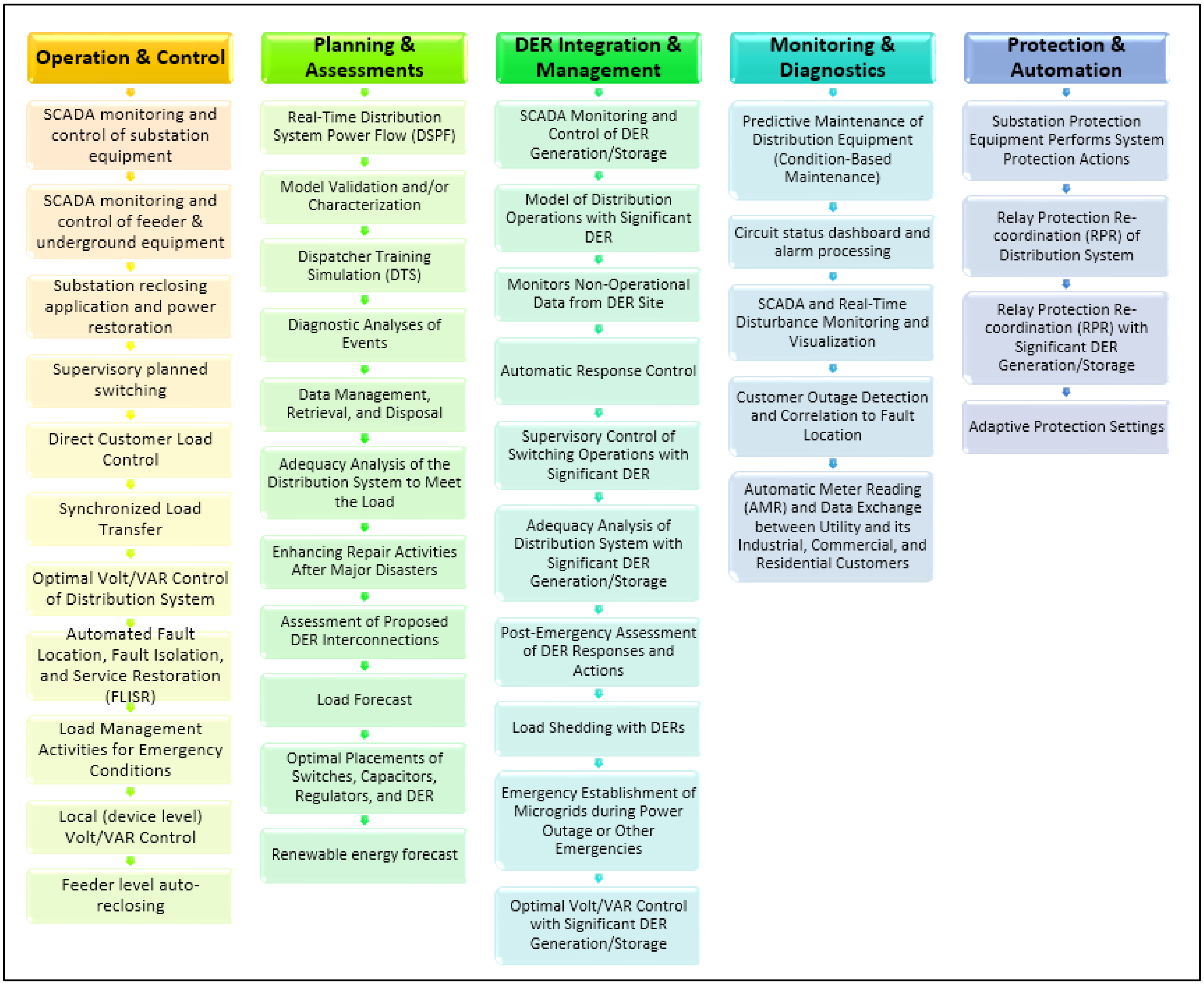


Figure 2-2. An overview of DA applications

2.1.3 Distribution automation maturity model

The objective of this section was to review some commonly implemented distribution automation (DA) applications and to define different implementation levels to allow utilities to benchmark themselves.

Eight (8) major DA applications were considered and four (4) maturity levels defined, ranging from “Traditional” to “Trendsetter”. Table 2.5 provides a list of DA applications reviewed in this study along with the definition of the maturity levels.

Table 2.5. Reviewed DA applications and their maturity level

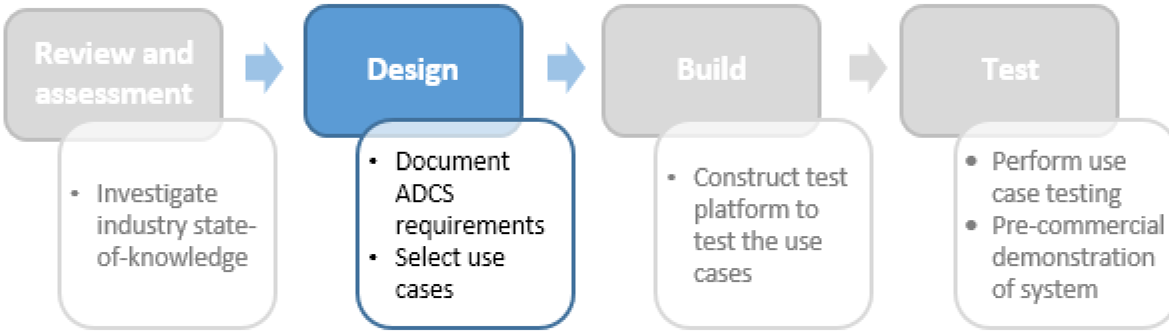
Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
Fault Location and Service Restoration	No information on status of various devices in the distribution system is available to the operator. There is no direct way to find out about the outages. Thus, the dispatchers depend on telephone calls from customers or a sudden change in power flow at a metered location. Technician then identifies the open device responsible for the outage and locates the cause of the outage. In some cases, overhead fault indicators can give indication of the direction of the fault to speed the location of the problem. Damage is cleared and isolated section is restored	Customer calls are cataloged and analyzed by the outage management system (OMS). The call pattern data predict the most likely device initiating the outage. Single Point status sensors may be available to confirm major device status (feeder breaker or recloser) in OMS. Technician travels to predicted device and confirms/corrects outage model. Restoration is modeled in OMS as technician manually updates progress.	Advanced methods require installation of sensors on feeders and customer-ends. Such an approach requires recording the time of interruption. The data is processed using a statistical technique to determine outage locations. Once the location is known, the faulted section is isolated with the help of remotely controlled switches, if the protective devices have not already isolated the fault. Subsequently, remote switching can be done to restore power to healthy parts of the system. The OMS, combined with SCADA and fault data, can accurately locate the faults. Some switching operations can be performed to partially restore service from the control center utilizing SCADA switches.	Combination of SCADA controlled devices and fault sensors allow for local or centrally managed location of faults, automatic isolation switching, and restoration where possible. This is commonly referred to as the FLISR (fault location, isolation and service restoration). The status of the switches that operated under the FLISR scheme are reported back to the OMS, and the information is provided to the technician. The technician then travels directly to the faulted area of circuit, clears the trouble, and requests the control room to return the circuit to normal. The OMS then returns the circuitry to normal operating conditions.
Feeder Reconfiguration and Transformer Load Balancing	Manual system reconfiguration is done on a seasonal basis. Distribution planners perform offline analysis on a circuit-by-circuit basis to determine the best circuit configuration for seasonal loading. Since such reconfiguration may require several manual switching	Circuit analysis is performed using recorded peak loading conditions captured by load recorders. Circuits' peak capacity are flagged for reconfiguration and the analysis is only performed on select circuits. Reconfiguration of the system for reliability and loss reduction	Some circuits/substations are analyzed in DMS through loading scenarios, and switching/reconfiguration suggestions are made to the operator. These suggestions can be performed using only remotely-controlled devices or a blend of remotely and locally controllable switches.	Optimization modules run on a predefined frequency to attain target goals (voltage profile, losses, CVR, etc.), and DMS recommendations are implemented immediately in the field utilizing remote switches. An operator/engineer would be notified of configuration changes and be able to override reconfiguration in the cases of

Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
	operations, it is not feasible to do it frequently.	can be done using the same switches which are used for fault isolation and service restoration. Switching is mainly performed in the field, with some remote switching via SCADA. Efficacy of load transfer is monitored via SCADA and Distribution Management System (DMS).	Since the system can operate sectionalizers remotely, system reconfiguration can be done as frequently as the operator desires.	emergency response or planned clearances.
Transformer Life Extension	Manual process: the dispatcher relies on trial-and-error to get proper level of loading. The dispatcher would close a switch to supply additional load with an expectation that the total load would be less than a certain value. But if the load is higher than expected, he would have to open the switch, drop a few feeders, and then close the switch again. The process would have to be repeated until the load is at a desired level. The switching of the load can stress the transformer significantly and, thus, reduce its total life.	It is similar to Traditional level, but there is some data monitoring including oil and transformer temperature using conventional SCADA. This level still needs few switching operations, but it is less than Traditional level.	Transformer oil level and winding temperature are monitored. Also, equipment for monitoring the health of the transformer based on dissolved gas analysis are available, as well as measurements from the feeder to which the transformer is connected. Since the feeder can be accessed by DMS, the balance between the desired loading and the feeder load can be monitored to control transformer overloading without additional switching. Thus, stress on the transformers can be avoided and its life will be extended. Fault Oscillography is available at the transformer bus to record through faults seen by the transformer.	Fully integrated and optimized within DMS system, to minimize stress on the transformers. Fault Oscillography is analyzed by DMS to evaluate I^2t exposure by substation transformer. Also, DMS alarms trigger for excessive fault duty or excessive cumulative fault exposure
Recloser and Breaker Monitoring and Control	Manual process: no remote monitoring and control is available. Recloser and relay settings are changed locally. In case of pole mounted reclosers,	Recloser/breaker statuses are monitored via SCADA, but their settings are adjusted manually. Monitoring helps to maintain recloser and breaker contact	Recloser/Breaker statuses are monitored and controlled via SCADA. The control functions include status change (Trip/Close), automatic reclosing	Advanced DMS/OMS with fully automated monitoring and control, health monitoring, and maintenance initiation is in place. Secured engineering access to

Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
	it is very time consuming to change settings. Further, since no monitoring is available, time-based maintenance is used for reclosers and breakers even if it not is necessary.	when needed. Number of operations can be recovered from SCADA to improve maintenance strategy based on operation frequency. In addition, load currents per phase, control battery voltage, and line voltage may be reported to SCADA.	enable/disable, ground relay enable/disable, and setting group change. This allows for better control of the system when the system configuration changes. This can be done via SCADA or DMS.	controls and configure relay settings is available so that operational profiles can be changes without requiring a technician to visit the control in the field. Fault data are captured to improve maintenance programs in DMS.
Capacitor Switching for Volt/Var Control	Installed capacitor banks cannot be monitored remotely. They are controlled locally, by sending the crew to the site or through local control (voltage, time of day, load current inputs, etc.)	Some of the installed capacitors may be remotely monitored via SCADA, while some of them are remotely controllable. The voltage regulation settings are determined based on assumed load curves, historical data, and offline analysis.	Capacitors are remotely monitored and controlled via SCADA or dedicated controllers. These controllers can be programmed to use a combination of several factors for capacitor switching. In some cases, the controllers can communicate with the central station. However, the controllers respond to local conditions and, thus, they do not provide the most optimal capacitor configuration. In other words, they cannot consider the network-wide impacts of capacitor switching, leading to potential overvoltage scenarios.	Advanced DMS applications (Loss optimization, Volt/Var Optimization, CVR, etc.) enable optimal capacitor switching for different load conditions. Meters measure V, I, P, and Q at different locations. The metered data as well as status of capacitors are sent to the DMS to determine optimal capacitor switching for the prevailing system conditions. AMI data is also used to support this functionality. DMS looks into the network and prohibits a device from closing into an overvoltage. Voltage exceptions not identified by DMS are flagged in DMS for follow-up.
Regulator Operation for Voltage Control	There is no voltage regulators in place.	The regulator is controlled based on local line voltage and maintaining a band-center setpoint with a proper voltage tolerance bandwidth. In advanced cases, line drop compensation is used to overcome large distances	Regulator voltage is monitored and controlled in DMS. Regulator voltage, tap position, and settings are fully configurable/controllable through DMS.	Operation of regulators is coordinated with capacitor switching to reduce losses and/or obtain better voltage profile under different load conditions. Regulator settings are controlled dynamically based on advanced DMS applications.

Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
		between the regulator and the load center.		
Transformer LTC Control	Manually or Locally controlled Load Tap Changer (LTC)	Tap position and LTC output voltage are monitored by SCADA. The control is normally done manually or as a function to load changes. The control is not typically implemented inside DMS/SCADA, but a separate control system.	Operation has supervision and control of the LTC through SCADA. Settings and positions are controlled through DMS.	The LTC is used as a part of the Volt/Var optimization, loss optimization, and/or CVR application. DMS prioritizes device operations based on operational objectives and impacts.
Distribution System Monitoring	Basic SCADA: Status indications of major equipment (circuit breakers and IEDs), No control and coordination with OMS exist; there is only basic local controls for Volt/Var equipment.	SCADA with basic DMS: Feeder circuit breakers and some three phase reclosers, capacitor banks, and line regulators are monitored and controlled. Load and voltage data can be monitored through DMS.	SCADA and DMS/OMS in place: Feeder circuit breakers, three phase reclosers, and Volt/Var equipment are monitored and controlled. Additional aerial and pad mounted sectionalizing device are also controlled. Status points are integrated with OMS model to instantly verify outages.	Full monitoring and control system, integrated with SCADA, DMS, and OMS Advanced applications with DERs integration, AMI/MDM, enterprise back office applications, and demand response Latest interface standards, communication protocols and cyber security in place

2.2 Distributed control system design



This task examined the architectural considerations for the proposed distributed control system using the findings from the previous task as a point of departure. It began by contrasting two different approaches to distribution control system design: centralized versus decentralized and finished by selecting three uses cases suitable for testing and demonstrating the proposed system.

2.2.1 Centralized approach

Conventional distribution control systems tend to be centralized in nature. As shown in Figure 2-3 below, a central control center communicates with an array of substation and field-based Intelligent Electronic Devices (IEDs) – polling them on a periodic basis to extract digital and analog data, and issuing commands to control primary apparatus and reconfigure the system, as and when human operators deem it necessary.

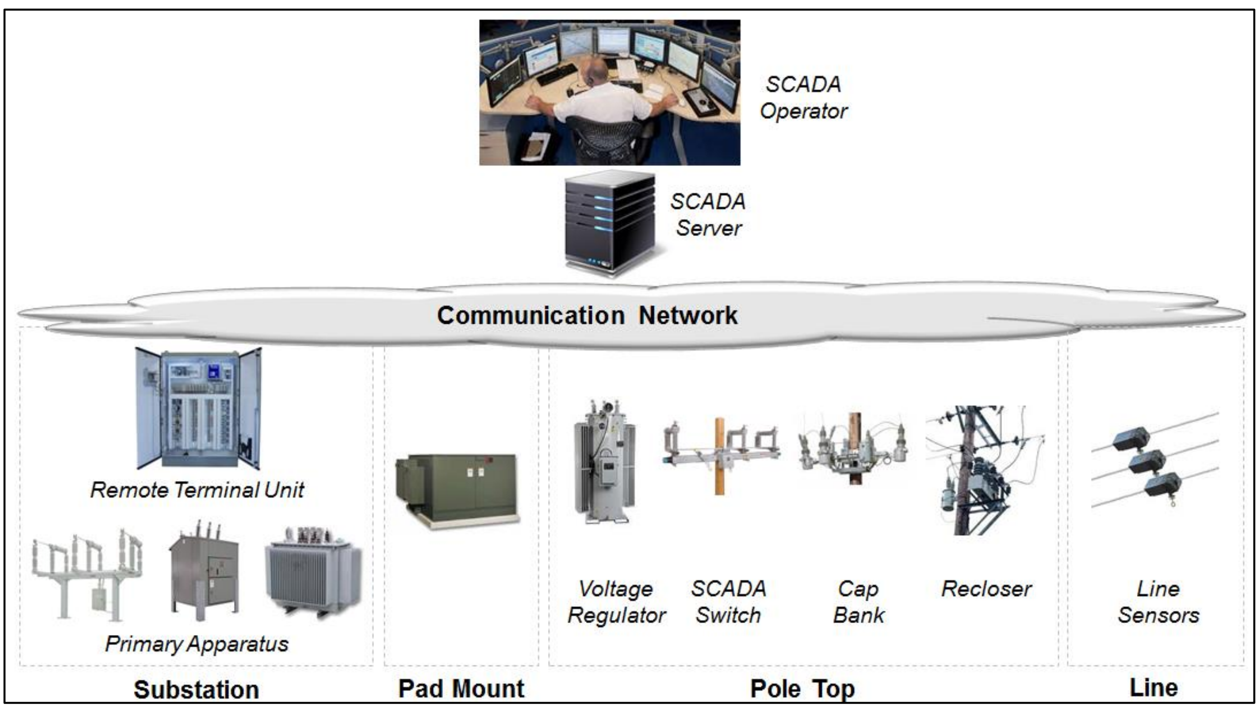


Figure 2-3. Simplistic representation of conventional distribution control system

The frequency with which the control center communicates with the IEDs is dependent on:

- The capabilities of the SCADA server in the control center and the presence, and number of, front-end-processors
- The type and speed of the communication network
- The communication protocol(s) in use
- The turn-around time of the IEDs
- The control mode: whether automatic or operator advisory

In most cases, round-robin data acquisition times of several seconds are the norm. Should an event occur on the power system that requires it to be re-configured, the time taken to do so is dependent on the capabilities of the operator to process the incoming data, determine the appropriate response and issue the necessary commands. Speed of response is typically measured in minutes, as illustrated below.

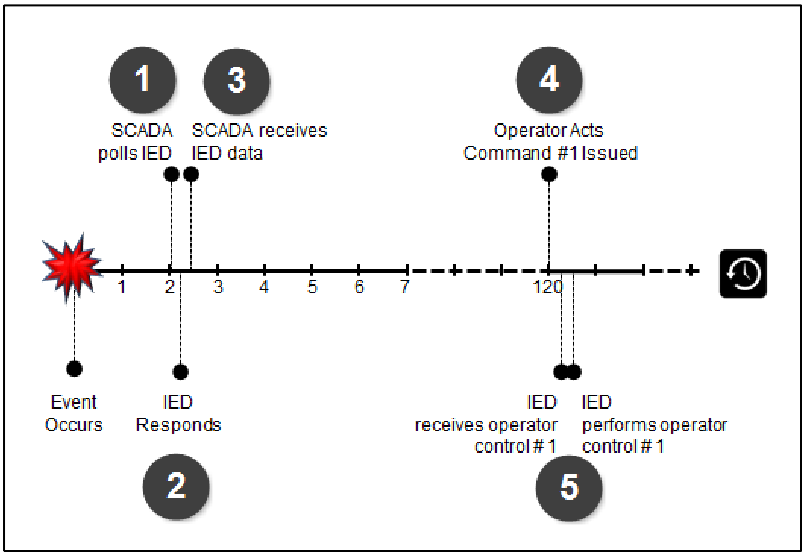


Figure 2-4. Sample event-to-action timeline – centralized design under operator control

Hypothetical sequence of actions showing manually generated operator controls:

- SCADA polls IED (assuming 2 second poll rate)
- IED responds (within 100 – 500 ms depending on IED vintage)
- SCADA receives IED data (dependent on communications baud rate. For example, it takes ~50 ms for a maximum length DNP 3.0 message at 64 kbps to be received at the SCADA, whereas the same message will take 2.64 seconds on a 1200 bps line)
- Operator acts (highly variable, and dependent on Operator's experience, type of event, amount of data, etc.)
- IED receives the first operator initiated control command and performs the requisite action. The time between receipt of message and initiation of the control is IED dependent, but in newer generation devices, largely negligible

It is possible to improve the speed of response by automating the decision tree and sequence of actions the operator undertakes for a given system event. A typical application for this type of automation is

Fault Location Isolation and Service Restoration (FLISR). Machine intelligence is deployed at the control center to detect fault scenarios, process the incoming data and follow a series of pre-programmed steps to isolate the fault and restore service to the maximum number of customers as quickly as possible. This is illustrated in Figure 2-5 below.

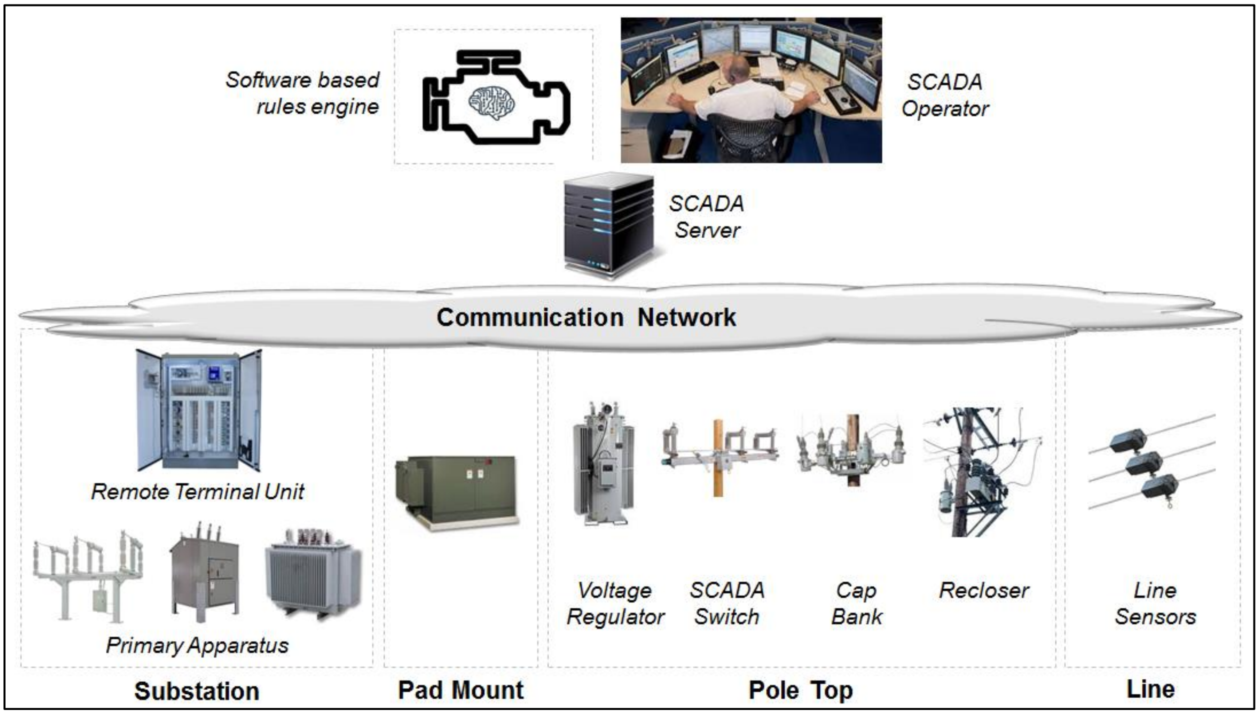


Figure 2-5. Simplistic representation of distribution control system with centralized automation

The equivalent event-to-action timeline is shown in

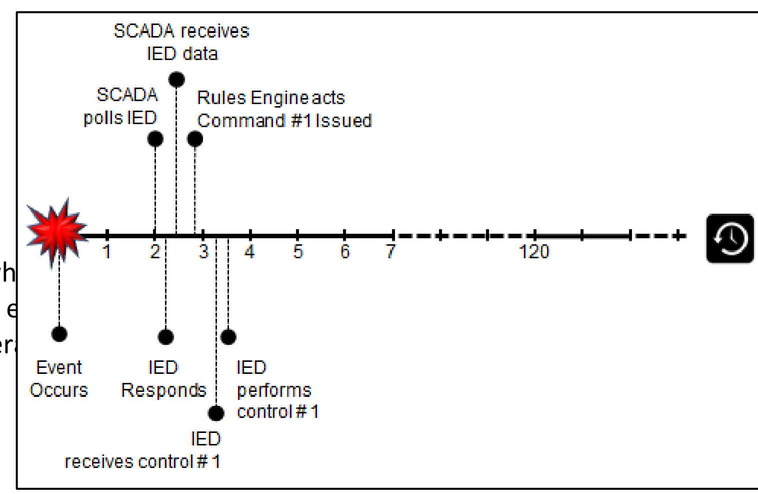


Figure 2-6 below, wh with a machine response. The rules e a fraction of the time it takes an oper onds.

Figure 2-6. Sample event-to-action timeline – centralized design under automatic control

The example above assumes that control commands are prioritized and the normal polling schedule is interrupted to send out-of-sequence communications to the IED that needs to be controlled. It is worth noting that for some applications the rapid response depicted above is neither necessary nor desirable. Certain delays may be required, for example, to allow reclosers to retry the requisite number of times before locking-out, and then only initiate the isolation actions. In these instances, the delays can be programmed into the rules engine and the response times, repeatability and quality of control decisions is guaranteed – **making automation an ideal way to improve the performance of a centralized system**.

2.2.2 Decentralized approach

The key premise of the decentralized approach is that decision making is driven to the lowest level possible and as close to the initiating event as feasible. The speed at which various control functions are performed can vary significantly depending on the control requirements and type of events with much less dependency on SCADA communications. In this case, the control center's role is that of a "supervisory systems", allowing high speed and time speed controls to be performed closer to the point of action.

Several technology advancements have made this decentralized approach possible:

- The advent of newer generation of IEDs with more processing power and communications ability
- The introduction of newer generation of communication protocols that allow for peer-to-peer communications
- The availability of IP-enabled, substation hardened communication equipment that have facilitated the gradual convergence of utility information technology and operational technologies (IT/OT)

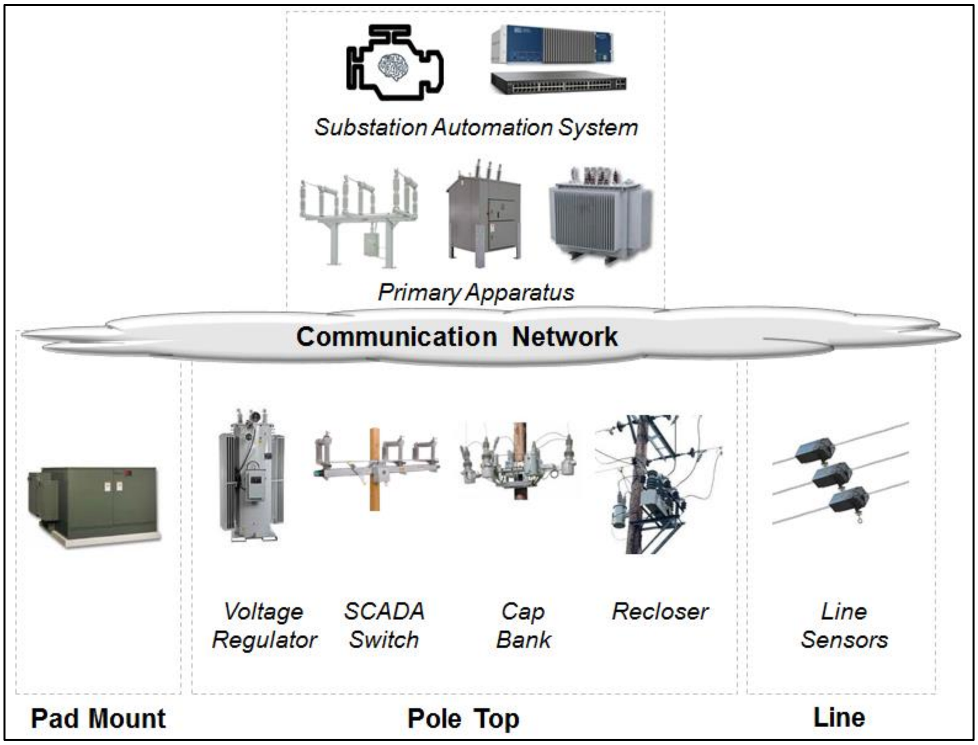


Figure 2-7. Substation-centric decentralized design

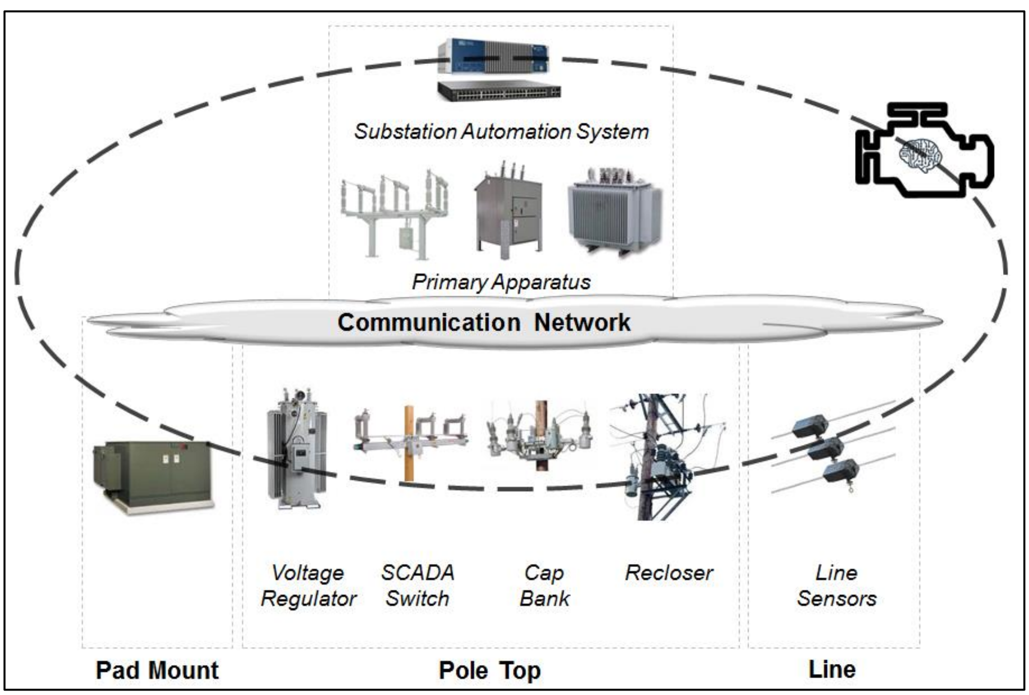


Figure 2-8. Peer-to-peer based decentralized design

Figure 2-7 and Figure 2-8 above illustrate two different approaches. The more conventional is the substation centric design where the processing power of the substation automation systems that are gradually replacing remote terminal units (RTUs) are used to provide a computing platform for the automation applications. It mirrors the centralized approach in that all data flows upstream to a single device – in this case the substation automation system – decisions are made and then distributed to the required IEDs. The associated event time line will look something like Figure 2-9:

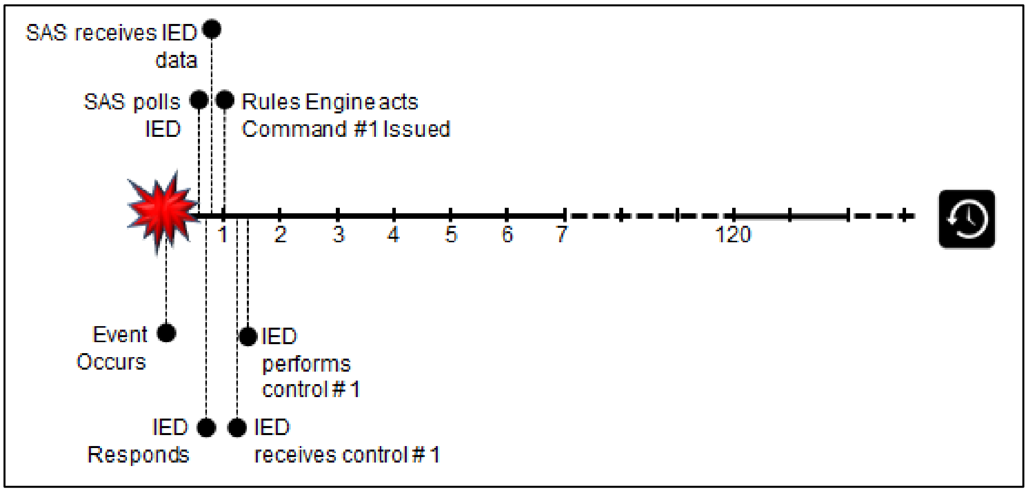


Figure 2-9. Sample event-to-action timeline – decentralized substation-centric design

Data acquisition times are reduced since there are less downstream devices that need to be serviced, so response times are faster than the SCADA-centric automated equivalent and measured in a couple of seconds. In contrast, the peer-to-peer approach is truly decentralized, and there is no central decision making rules engine. Requisite data are published to all devices that have registered to receive them and decision are made by the IEDs, all of which are required to have sufficient processing power to implement portions of the rules-engine.

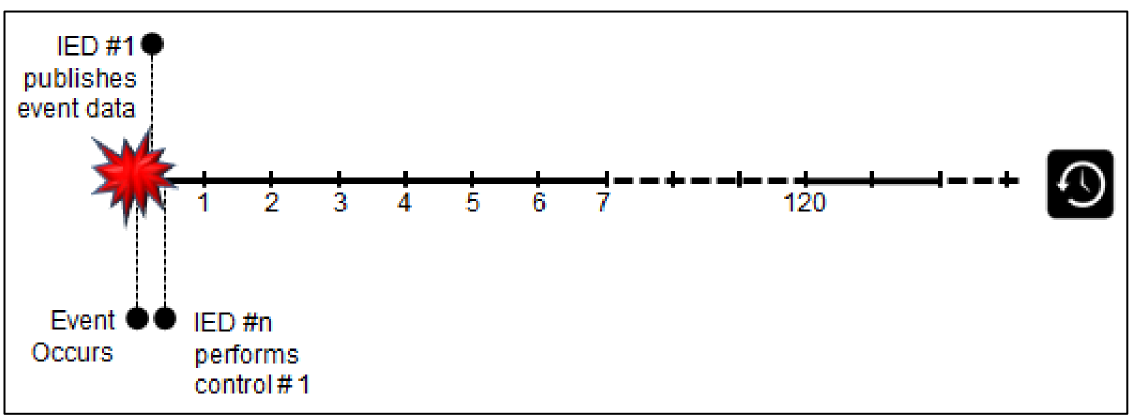


Figure 2-10. Sample event-to-action timeline – decentralized peer-to-peer design

The timeline is even more compressed and sub-second response times are now possible. As noted previously, there are some applications where this high-speed response can be fully utilized and others not.

2.2.3 Centralized versus decentralized - pros and cons

There are advantages and disadvantages to both centralized and decentralized approaches – summarized below:

Table 2.6. Comparison between centralized and decentralized control approaches

Parameter	Centralized	Decentralized
Situational awareness	Comprehensive The as-switched status of every system component is available (subject to whatever restrictions apply from communications connectivity and update times) The advantage of the centralized man-in-the-loop is the ability preview the situation before changes are made	Limited Restricted to the local area - substation or lower. Any information from neighboring substations has to be fed downstream from the control center in a convoluted manner – possible, but inelegant – that is unless a peer-to-peer connection can be made.
Speed of response	Low As discussed	High As discussed
Accuracy	Restricted The delays imposed by the “man-in-the-loop” may limit the accuracy of the selected solution, because changes during the decision process may require a new decision or approval cycle	Optimal The solution is implemented as soon as possible following an event, minimizing the likelihood that the solution is invalidated by another event. Once the solution is implemented, the system is armed for the next event as soon as possible
Resiliency	Very heavily dependent on communication infrastructure and any interruptions in service halt all transactions	For the most part can act autonomously from the control center so status of upstream communications has no impact on ability to operate
Maintainability	Easy from the perspective that all logic is managed in one location. However, depending on the vintage of the system, the entire model may require updating, making the process cumbersome and time consuming	The logic is present in multiple locations which can require more steps to make modifications. However, it does have the advantage that the model can be updated incrementally without impacting other non-affected parts, making updates simpler and faster
Personnel safety	More reliant on human intervention and therefore more susceptible to human error	Faster response times and deterministic behavior should improve personnel safety

Parameter	Centralized	Decentralized
Scalability	Determined by the SCADA server capacity and capability, as well as communication infrastructure	Highly scalable, with less dependency on SCADA backbone
Physical and cyber security	Typically have better and comprehensive physical and cyber security postures than de-centralized control systems. Standards for protecting centralized systems are further evolved than standards for de-centralized systems. Unauthorized access to centralized systems puts more assets in jeopardy than in a de-centralized system	More access points and commensurate increase in complexity to protect
Technological enhancement	Has to be implemented in steps and at some point may require a complete overhaul of the SCADA backbone, which increases the capital cost investment	Gradual and continuous, requiring lower capital investment
Dependent on	Access to a reliable and high speed / high bandwidth communication system with high resiliency. Redundant SCADA servers and fast and seamless fail-over mechanisms to prevent SCADA downtime	Local processing capabilities in the IEDs and peer-to-peer communications for some applications

2.2.4 Components of a distributed control system

The main components of a distributed control systems are:

1. Control platform that is a combination of logic/algorithms programed in hardware devices and software programs
2. Control applications: a series of applications that target specific objectives and/or coordinated actions
3. Communications system: a mix of hardwired and/or wireless methods for transferring data and commands between the components of the control platform
4. Database (on a server or a cloud) for data gathering and data sharing among the applications
5. End devices:
    - Feeder level devices, including: SCADA switches, reclosers, capacitors, voltage regulators,

- DER devices: energy storage systems (ESS), PV systems, power conditioning units, other distributed generation (DG) units

6. Measurement sources:
   - Non-SCADA measurement devices (*e.g.*, advanced metering infrastructure (AMI))
   - Measurement from SCADA devices on the circuits
   - Measurements through RTU devices at the substation

2.2.5 System requirements - general

The main functional requirements for a distributed control system irrespective of target applications and/or end-devices as part of the control are tabulated below:

Table 2.7. Functional requirements for a distributed control system

Parameter	Functional requirements
Proven and innovative solution	A distributed control system (DCS) technology should be proven in the most demanding automation environments. It should also offer innovative solutions vital to improved system operations in a fiercely competitive climate. Major areas to apply innovative and proven solutions are: • Proven communication networks for fault tolerance, performance and security • Stable and time-tested controllers and device-level interface design • Versatile and robust control environment with proven control algorithms • Pre-built template and rich function libraries enabling rapid implementation of best practices • Built-in function blocks specific for power applications and distribution system automations • Advanced batch file control capability
Built-in redundancy	True redundancy is required in all levels of the system from the I/O all the way up through the I/O link, the controllers, the network and the servers. There should be no single point of failure in the entire process. In addition, fail safe consideration should incorporate transferring of the controls and commands to alternative devices and/or platforms to maintain certain level of autonomous operation, as long as there are no drastic change in operating conditions.
Integrated platform environment	The DCS platform should allow direct access to controllers for process data, alarms and messages for constant view and control of the process. Also, the integrated platform facilitate data exchange and utilization freely among various players and components.
One data ownership	By sharing a singular database across controllers and human machine interfaces (HMIs), it helps maintain global data consistency while enabling greater usability and operability.
Simple configuration and use of	Distributed controls in the new environment heavily rely on advancement of monitoring and visualization to assist the operators in area awareness and making inform decisions. Hence, the higher focus should be given to the HMI capabilities and features, such as:

Parameter	Functional requirements
visualization system	• Standardized display library • Multi-level hierarchy windows with single click navigation • Pre-built equipment templates for easy configuration and maintenance • Bulk configuration tools that eliminate repetitive manual tasks • Dynamic alarm suppression that simplifies plant operations • Trending and playback capabilities for forensic analysis
Flexibility to expand control	The control platform should be able to easily handle integration of new devices and control processes without imposing unnecessary limitations. Distribution systems are evolving with the fast pace of changes occurring in the underlying technology and customer expectations. The controllers should be able to: • Grow to fit the emerging needs • Implement control where it is necessary

2.2.6 System requirements - layers of controls and requisite speed

For the purposes of defining the requirements of the proposed advanced distributed control system, the system elements were assigned to different functional levels as illustrated below. One of the primary differentiating characteristics between the layers, in addition to attributes like applicable industry standards, security, redundancy requirements, etcetera, was the speed of control performance. The applicable time domains of control performance are included below.

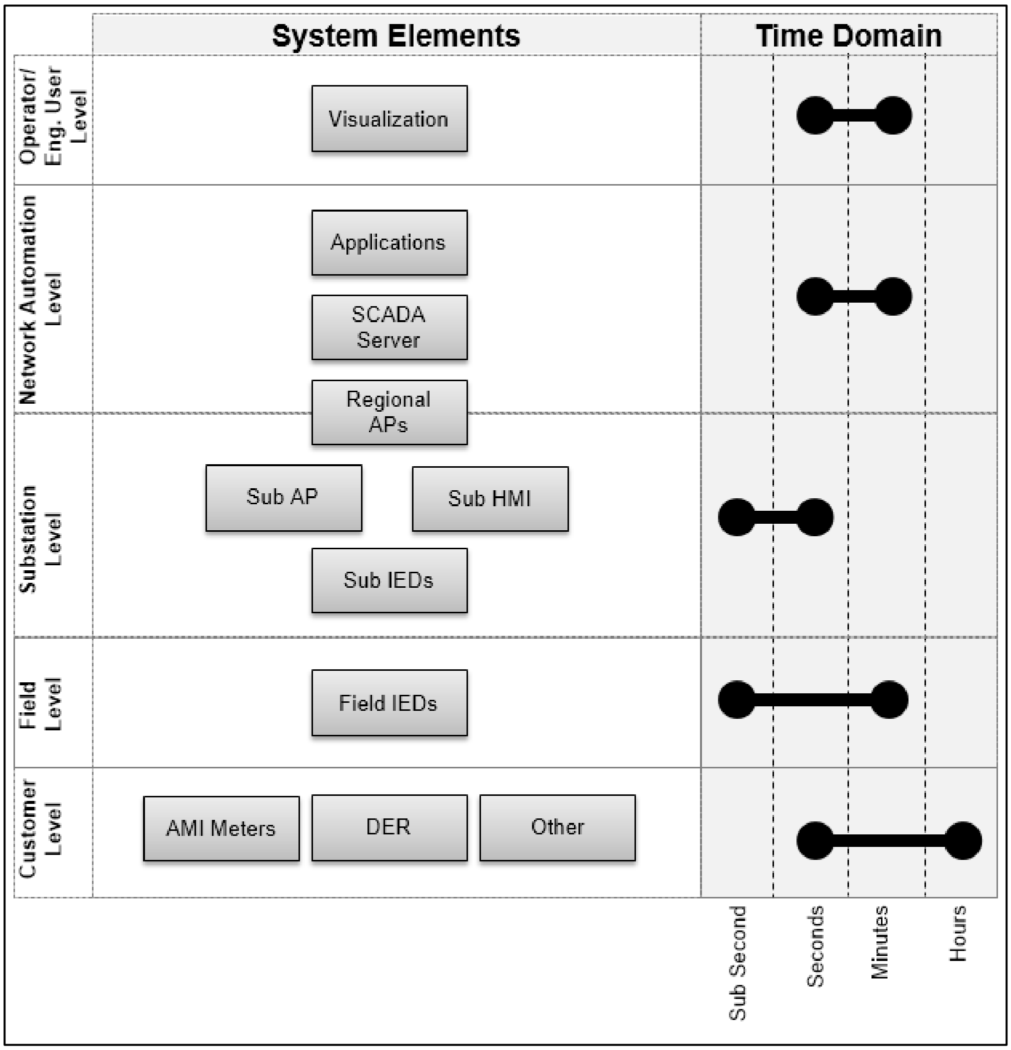


Figure 2-11. System elements at the various levels

Most of the system elements are self-explanatory and have been introduced in the preceding discussions (*e.g.*, the various types of IEDs, SCADA Server, etc). One new element that forms the basis for the ability to truly distribute control and automation functionality is the Application Processor (AP). This is a generic term for an automation engine that has the ability to interface with other devices, extract data from them, make high-speed autonomous decisions and communicate the results as commands and notifications. As shown, this could take the form of a substation-based AP, responsible for managing the operation of the substation and associated feeders, or it could be a Regional AP, responsible for managing the operation of multiple substations in a region. The ability to distribute the logic and adjust the extent of the area under control is key to creating a system that can scale and be future proof and forward compatible.

2.2.7 Use case selection

As part of Distributed control system review and assessment task, the project reviewed the publicly available information to identify all potential DA applications and use cases. After discussions with project stakeholders, a short list of three use cases were selected that best allowed for the comprehensive validation and testing of the proposed distribution control architecture – these are identified below, and described in more detail in the sections that follows:

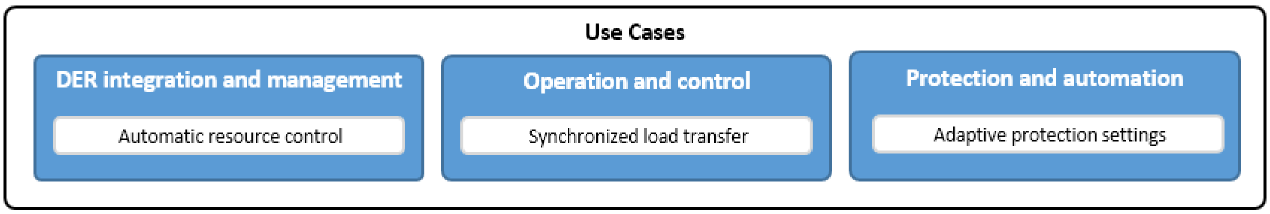


Figure 2-12. Selected use cases

Use case 1 - Automatic response control

Advanced distributed control techniques in distribution systems require close coordination amongst all the controllable equipment, including but not limited to DERs, capacitor banks, tap changers, voltage regulators, etc. With the proliferation of DERs, and the advent of advanced distribution automation applications, the operating principles of distribution systems are challenged. One method to address these challenges is to control controllable field equipment as well as dispatchable DERs such that system performance criteria including circuit loading, voltage profile, and losses are met. In particular, fine tuning/control of DER output powers (real and/or reactive power) can significantly reduce unnecessary stresses on system assets. The Automatic Response Control (ARC) application is used to reduce electric feeder losses and to flatten the Voltage profile of the feeder while maximizing the injection capability of the renewable devices, despite there being multiple feeder injection points.

Advanced strategies are needed to mitigate the adverse impacts of DERs on the distribution system while harnessing the benefit offered by them. The general philosophy is that DERs should generate at unity power factor (*i.e.*, no reactive power contribution). However, smart inverters offer advanced functionalities (including real- and reactive-power control) that can potentially improve grid stability and voltage regulation. Further, coordinated control of field devices such as load tap changers, voltage regulators, and capacitor banks can optimize the performance of the power system and facilitate integration of DERs into the electric grid.

Use case 2 - Synchronized load transfer for renewables

The effects of DERs on the performance of the distribution system may no longer be adequately managed by conventional approaches. The Synchronized Load Transfer (SLT) function, capable of changing circuit configuration through corrective automated switching actions, is one of the new control techniques that can help with integrating DERs into the electric grid.

The main objective of the SLT is to achieve the optimal configuration of distribution circuit(s) in order to improve operating conditions such as voltage profile, load balance, losses, overloading, and/or to prevent excessive reverse power flow from local distributed generation (*e.g.*, PV production). Under normal conditions, the SLT is performed when the circuit operating conditions cannot be improved through the automatic resource control (*i.e.*, control of load tap changers, voltage regulators, capacitor banks, and/or distributed generators).

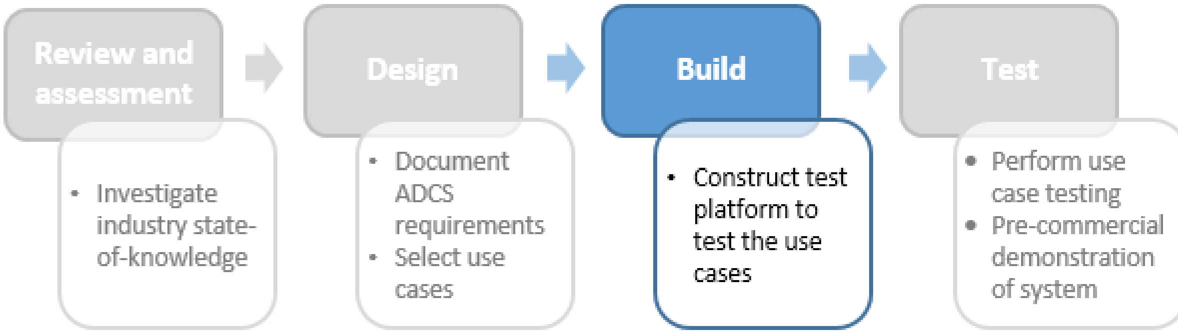
Use case 3 - Adaptive protection settings

The effect of distribution system changes on the protection system is traditionally managed by determining the relay settings for worst-case scenarios. With the high penetration of DERs and advent of distribution automation applications, this approach will no longer be adequate. Therefore, automatic protection setting change capable of changing protection setting groups based on the system topology can improve the protection system reliability.

The Automatic Protection Setting (APS) is a near-real-time activity that automatically modifies the protection setting groups in response to a change in system conditions or (forecasted) configuration in a timely manner by means of externally generated signals or control actions. It is a distributed control application that requires access to the state of switching device, protective devices, and Intelligent Electronic Devices (IEDs). Based on the state of the switching devices received from IEDs or other changes in the system configuration, the APS will change protective setting groups in one or more relays to prevent protection mal-operation and/or mis-coordination.

The main objective of the APS is to adapt the protection system to change in the power system condition and/or topology in order to improve the reliability and quality of service while incorporating advanced capabilities for optimal management of the distribution system.

2.3 Distributed control system test platform construction



2.3.1 Substation selection

Rather than constructing an entirely artificial test platform, the decision was made to pick two substations that met the selection criteria and then model these. The following attributes were considered during the selection process:

- Two substations that could be electrically connected through a Tie switch or breaker to investigate the impact of distribution automation applications
- Circuits with a high penetration level of DERs
- Circuits with lower than average reliability (SAIDI)
- Circuits with issues related to performance (losses, circuit loading, etc.) and/or power quality (voltage quality issues, etc.)

After evaluating these criteria, Substation “A” and Substation “B” best met the criteria for the reasons enumerated in the table below.

Table 2.8. Substation selection rationale

Criteria	Characteristics
Substation proximity	The selected substations were fairly close to each other with tie switches between them. Furthermore, there were tie switches between the circuits of each substation that provided the potential for implementation of distribution automation functions.
DER penetration level	Substation A and Substation B were among the 20 substations with the highest level of DER penetration. • Substation A had the highest level of DERs in its circuits • Substation B had the second highest energy storage system installation
System reliability	Substation A and Substation B were among the 10 substations with the highest SAIDI and system average interruption frequency index (SAIFI) values
Circuit performance	Substation A and Substation B were among the 10 substations with the highest level of capacitor failures. The main reasons for capacitor failure are normally

Criteria	Characteristics
	overheating, over-voltages, and voltage imbalances, all of which indicate performance issues.
Power quality	Substation A and Substation B were among the 10 substations with the highest level of highest level of voltage imbalance – possibly as a result of the high DER penetration level as well as load diversity in the circuits fed by these substations.

A simplified version of the resulting system single line diagram of the two substations and the respective feeders that are tied together via a tie breaker are represented in the following figure.

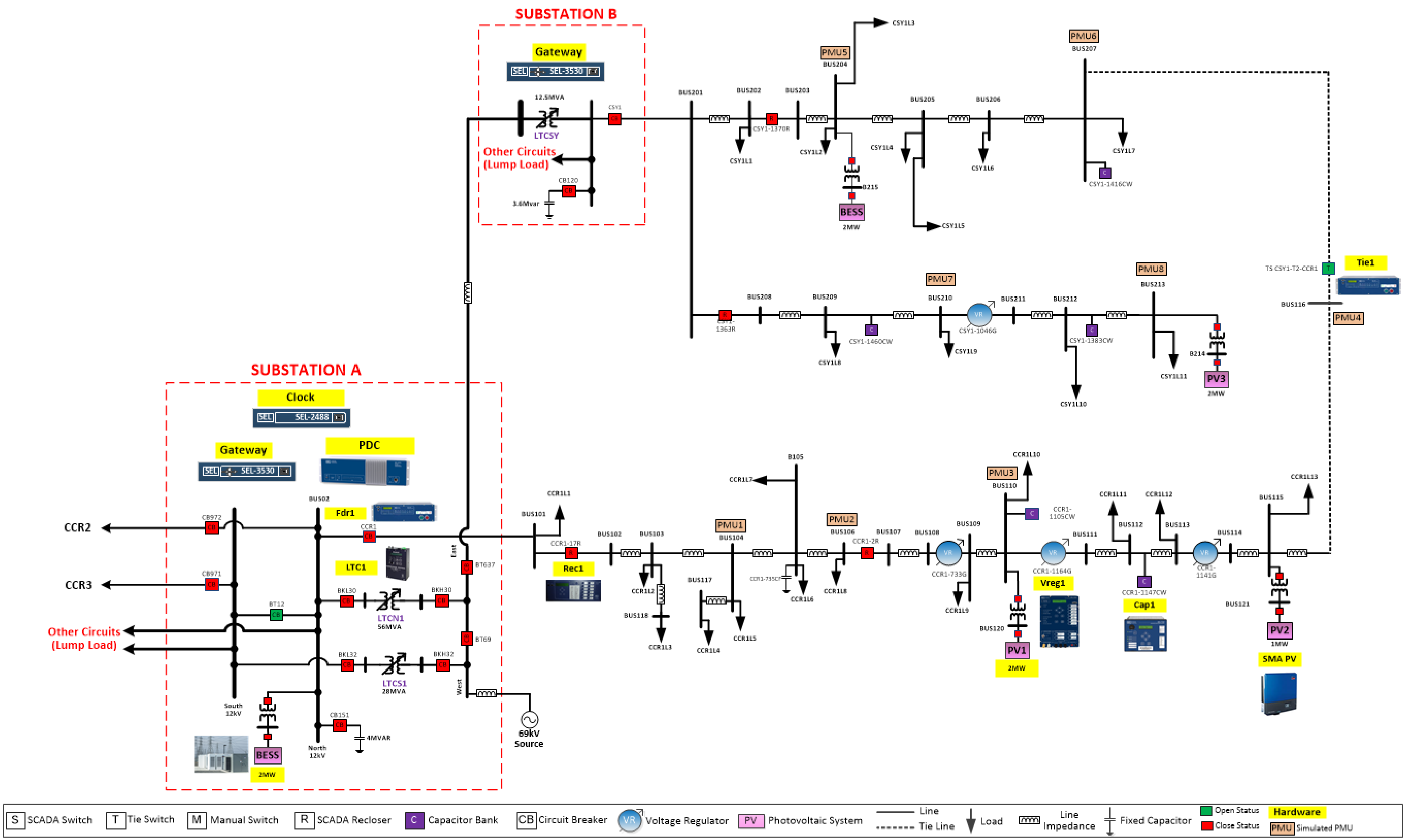


Figure 2-13. Single Line Diagram (SLD) of distributed control system test platform

The power components included in the model are listed in the table below.

Table 2.9. Power components of circuits CCR1 and CSY1

Item	Device	Quantity of Components in	
		Substation A (Circuit CCR1)	Substation B (Circuit CSY1)
1	LTC	2	1
2	Circuit Breakers	10	1
3	Line Recloser	2	2
4	Voltage Regulators	3	1
5	PV system	2	1
6	Shunt Capacitors	2	3
7	Tie Switch	1	N/A
9	Battery energy storage system	1	1

While much of the system was modelled in the digital simulator, extensive use was made of actual hardware devices – both IEDs and DERs. These are indicated in yellow in the Figure 2-13 above, as well as listed in the table below:

Table 2.10. Physical hardware IEDs included in the test setup

Item	Device	Location		Abbreviation
		Substation A	Substation B	
1	Feeder Protection Relay (CCR1)	x	-	Fdr1
2	LTCN1	x	-	LTC1
3	Recloser CCR1-17R	x	-	Rec1
4	Voltage Regulator CCR1-1164G	x	-	VReg1
5	CAP CCR1-1147CW	x	-	Cap1
6	PV 2	x	-	PV2
7	Tie Switch TS CSY1-T2-CCR1	x	-	Tie1
8	BESS 1	x	-	BESS1
9	PDC	x	-	PDC

The capability of switching from simulated IED models to physical IEDs was also implemented in the design of the test system to compare the control functionalities of the system controllers in dealing with real hardware as well as simulated (simplified) devices.

Each hardware IED also had a simulated version modelled in the digital simulator. This allowed the project to run the system completely independent of the hardware units to test and verify the communications interfaces and control logic without using any hardware-in-the-loop. Once the testing of the “all-simulated” base system was completed, individual hardware units could be brought on line to replace the simulated equivalent.

A simple, but elegant, mechanism was implemented to manage the switch-over from the simulated environment to the physical realm. The control and monitoring points associated with each IED were duplicated in the substation controller. A software toggle accessible from either the Local HMI or the master controller determined which data set was used for any local distributed logic, and fed upstream to the master controller.

2.3.2 Test platform design

The test platform architecture incorporated three layers of controls, namely:

- A master controller located in the control center which was used to perform optimization functions and coordinate the operation of field-based (lower level) controllers.
- Substation-based controllers – one in each substation – that acted as gateways for connecting substation and feeder IEDs to the control center and which were responsible for control logic specific to that substation and downstream feeders.
- Substation and Feeder IEDs that were the lowest-level controllers in the test system.

Figure 2-14 below shows how these three different control levels map to the conceptual distributed control architecture discussed previously. As shown, the master controller could be either a Regional Application Processor (AP) or a centralized SCADA Server plus applications. The substation controller represents the substation-based AP, and the local controllers are the substation and feeder based IEDs.

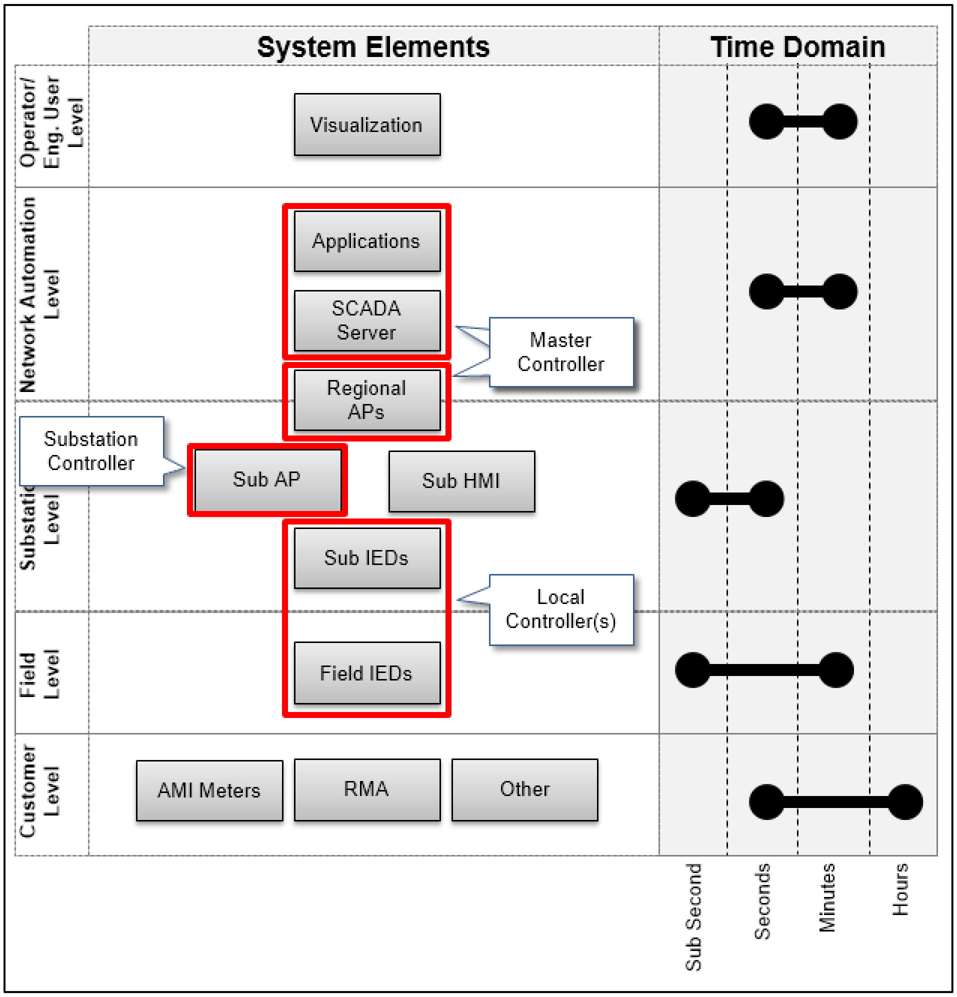


Figure 2-14. Three levels of control in the test system

Figure 2-15 below illustrates the interconnections between the various elements utilized in the test setup.

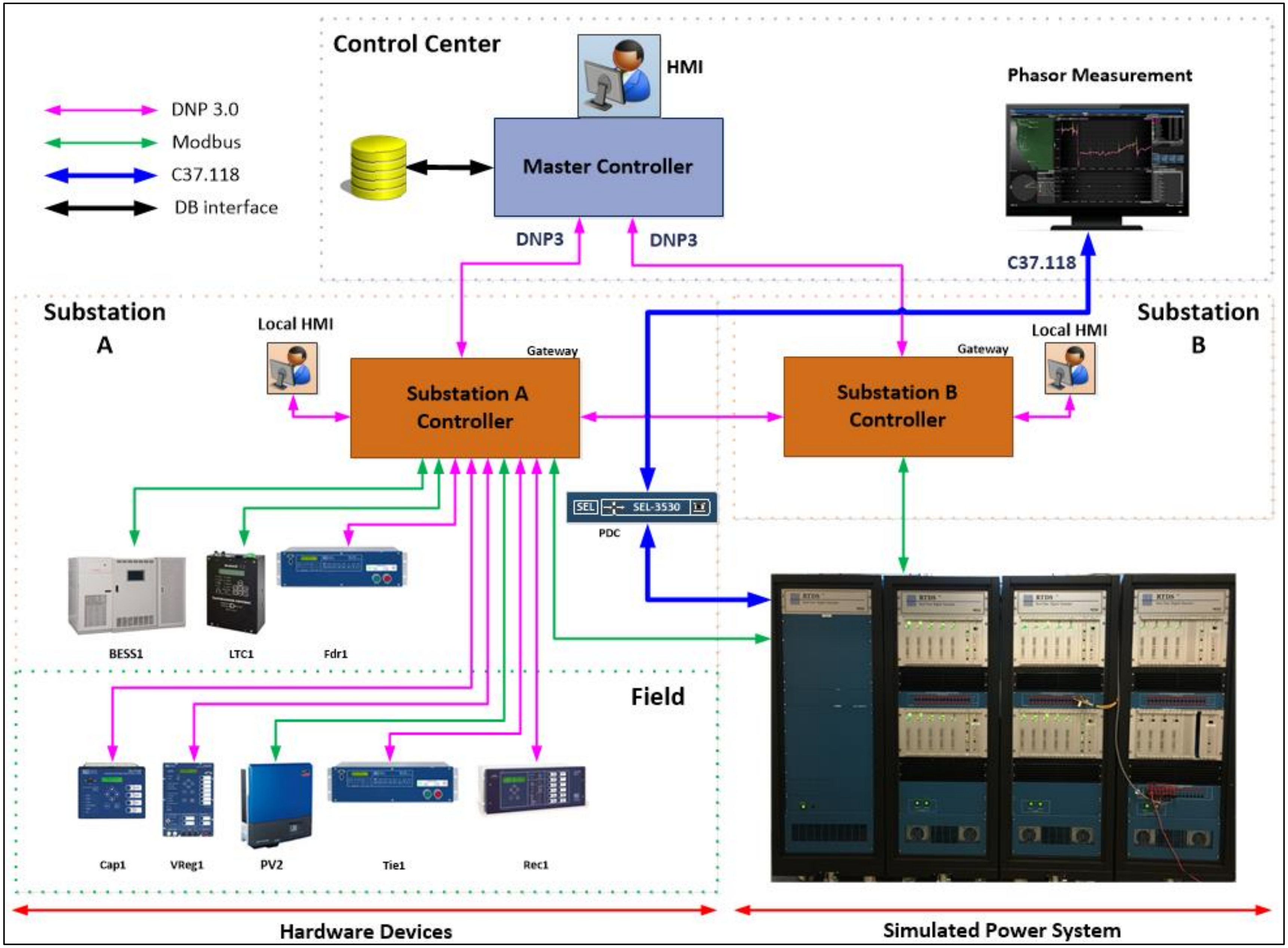


Figure 2-15. Communication architecture of distributed control system test platform

The table that follows provides a description of the functionality provided at the three different control levels.

Table 2.11. Key platform elements

Device	Description
Master controller	The master controller used a commercial SCADA package from Advanced Control Systems to run supervisory control functions for the entire test platform. Functionality included: • Acting as an automation engine for the control and automation functionality required to execute the requisite logic for the three use cases • Providing an operator interface from which control commands and setpoints could be issued to downstream devices • Providing an operator interface where digital, analog and accumulator data could be viewed, trended and alarmed upon. • Acting as a source for the data for the PI System, the primary repository for system data generated during the various use cases for later analysis • Acting as a secondary data repository
Substation controller	The two substation controllers were implemented on SEL RTACs. Functionality included: • Acting as automation engines for the control and automation functionality required to execute the distributed logic for the use cases for those instances where control responsibility was ceded to the Substation Controllers – either by operator command, or as a result of loss of communications between the substation and master controllers • Acting as data concentrators for both substation and feeder based IEDs • Acting as control and monitoring gateways between master controller and the substation and feeder based IEDs.
IED-level Controllers	The lowest control level was the individual IEDs, some of which possessed programmable logic functionality, although there were restrictions on the processing power available in specific IEDs that curtailed the extent of the logic that could be implemented. Functionality included: • Protection against overcurrent • Local (discrete) voltage adjustment (LTC and Cap Bank controller) • Local voltage tuning (through DER droop mode, if supported)

2.3.3 Test platform construction

The various hardware components were installed in two 19” racks as illustrated in the figure below.

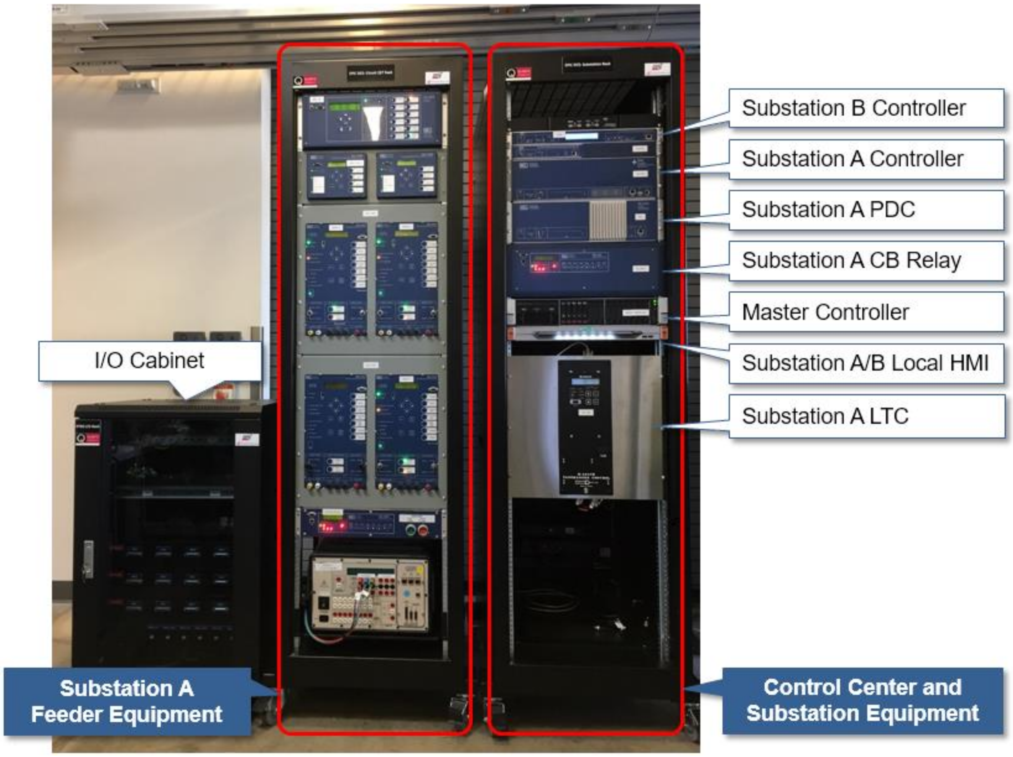


Figure 2-16. Test platform racks

The rack to the right in Figure 2-16 above was used to house the control center and substation equipment from both substations, while the one on the left was used for all of the IEDs on Substation A's CCR1 circuit. An additional, smaller, rack was provided to house the digital simulator I/O cards that were providing the hardwired inputs to the substation and feeder IEDs, as well as interfacing with the battery energy storage system (BESS) and smart inverter.

Figure 2-17. Master Controller HMI (deployed)

The master controller was equipped with an HMI that provided a graphical representation of the two substations as well as the various operator interfaces to control and monitor the substation and feeder equipment as shown in Figure 2-17 .

Figure 2-18 shows a typical HMI screen at the Master Controller.

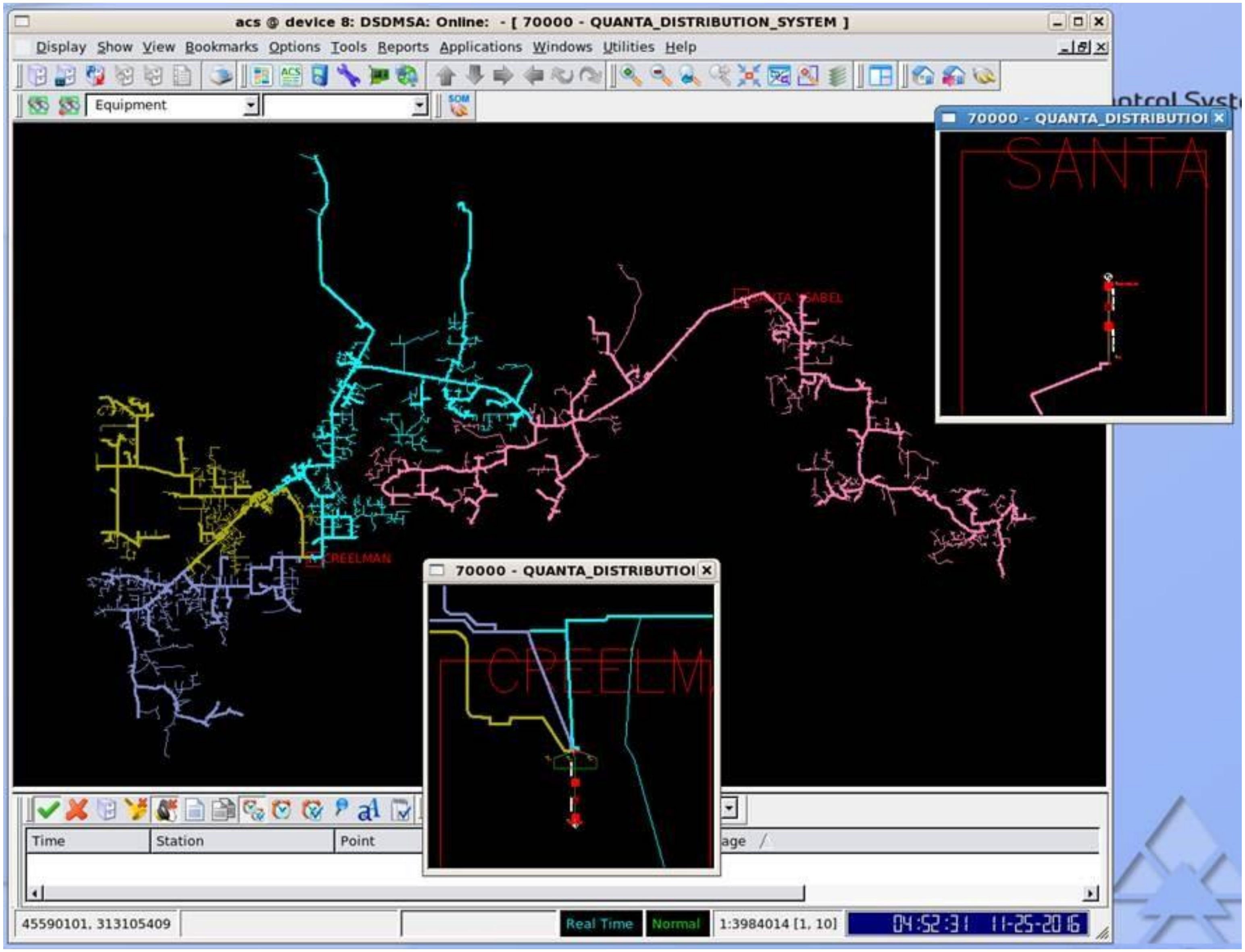


Figure 2-18. Sample HMI screen at the Master Controller

As illustrated in Figure 2-15, both of the Substation Controllers were equipped with local HMIs. These were web-based and accessible via a simple browser. Several examples of screens are presented in the figures that follow.

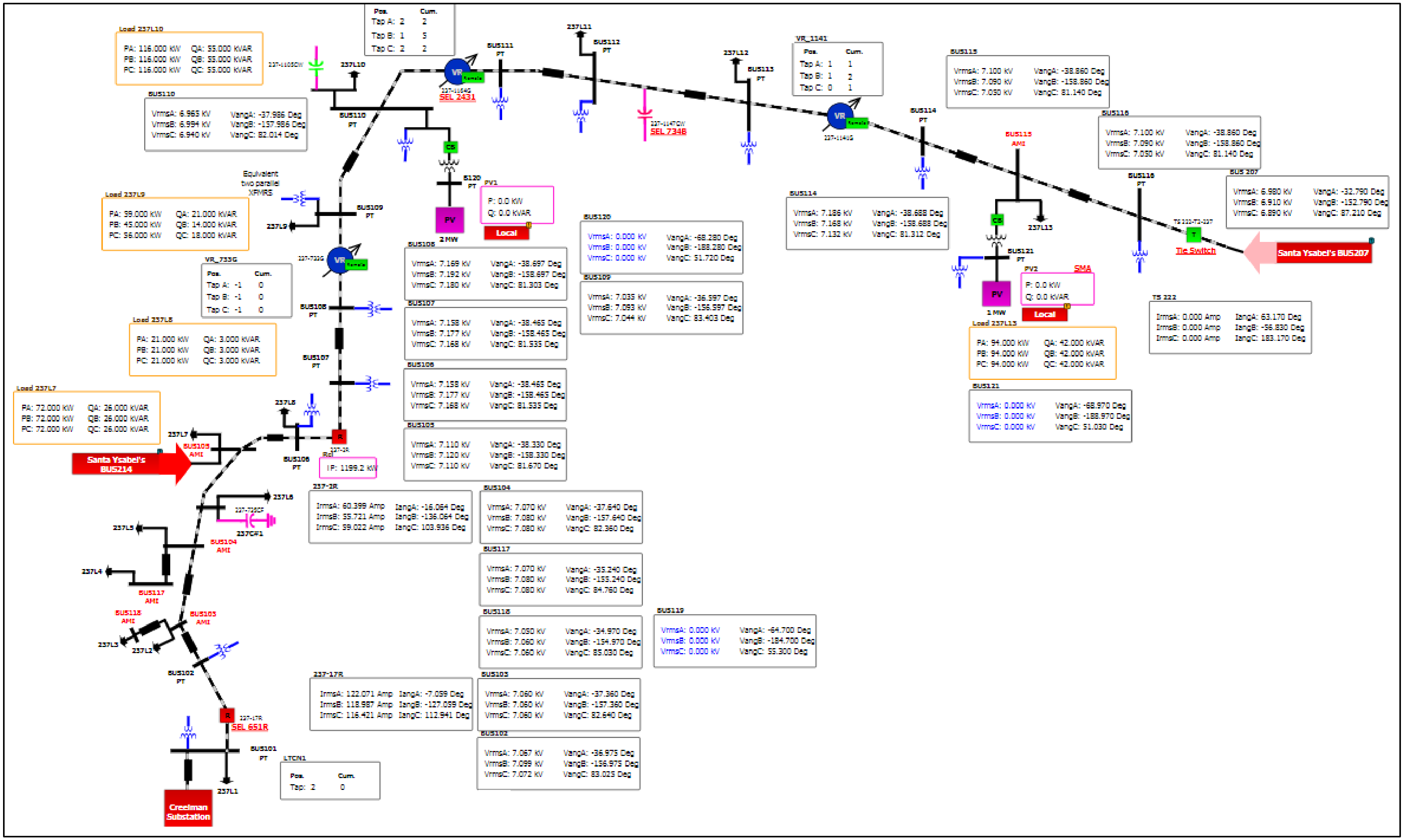


Figure 2-19. Substation A and circuit CCR1 topographic representation in the local HMI

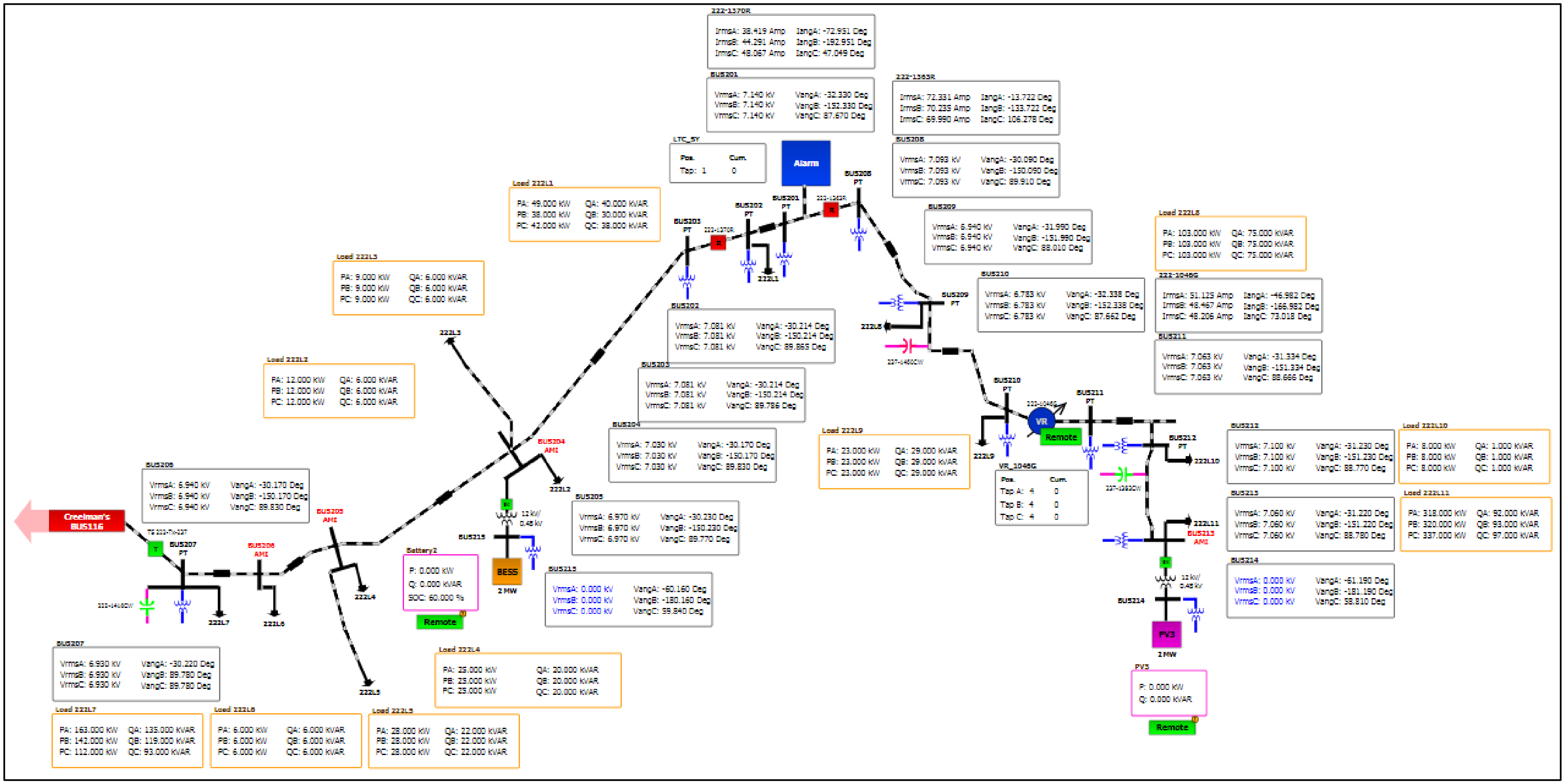


Figure 2-20. Substation B and circuit CSY1 topographic representation in the local HMI

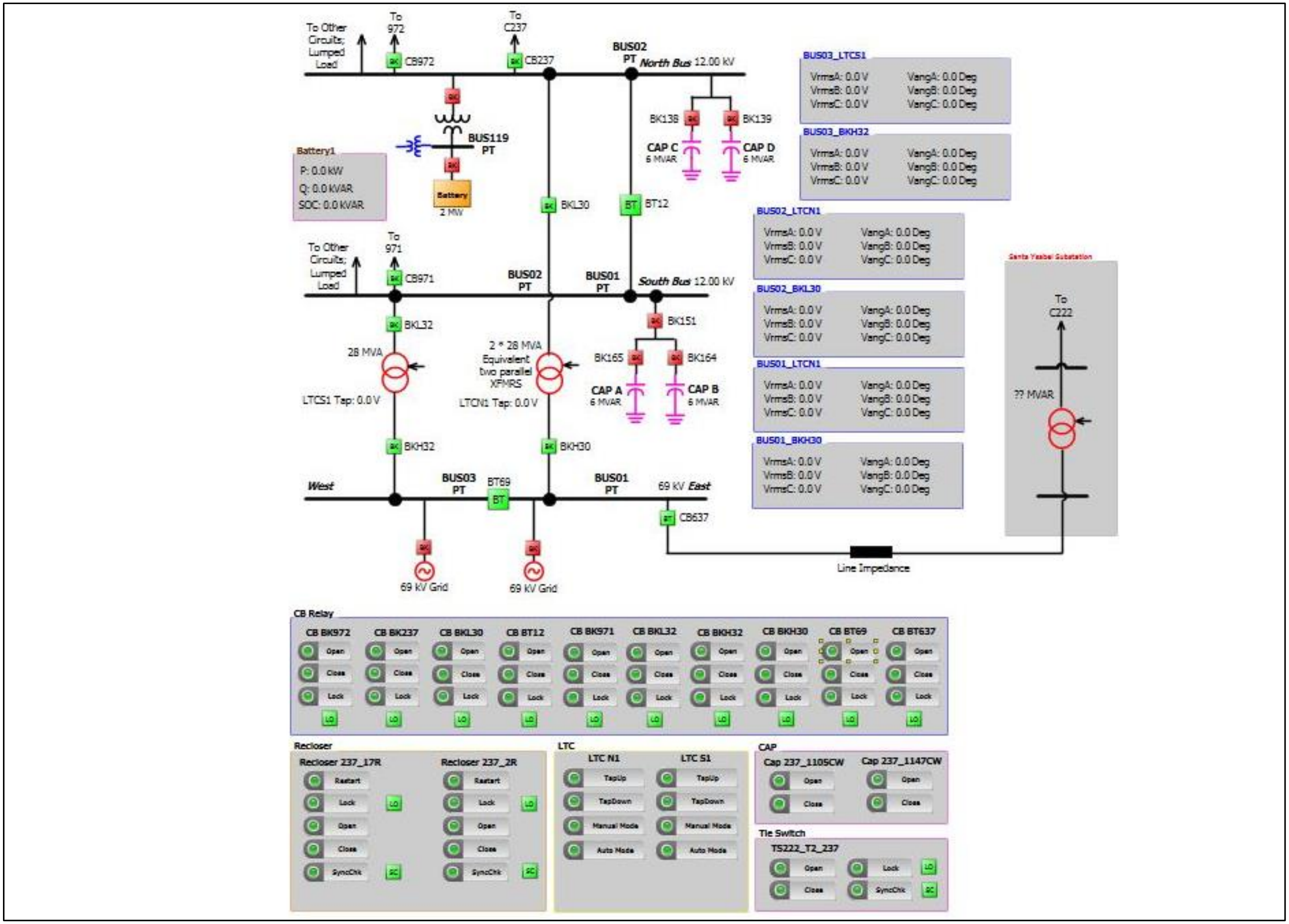


Figure 2-21. Substation A SLD in the local HMI

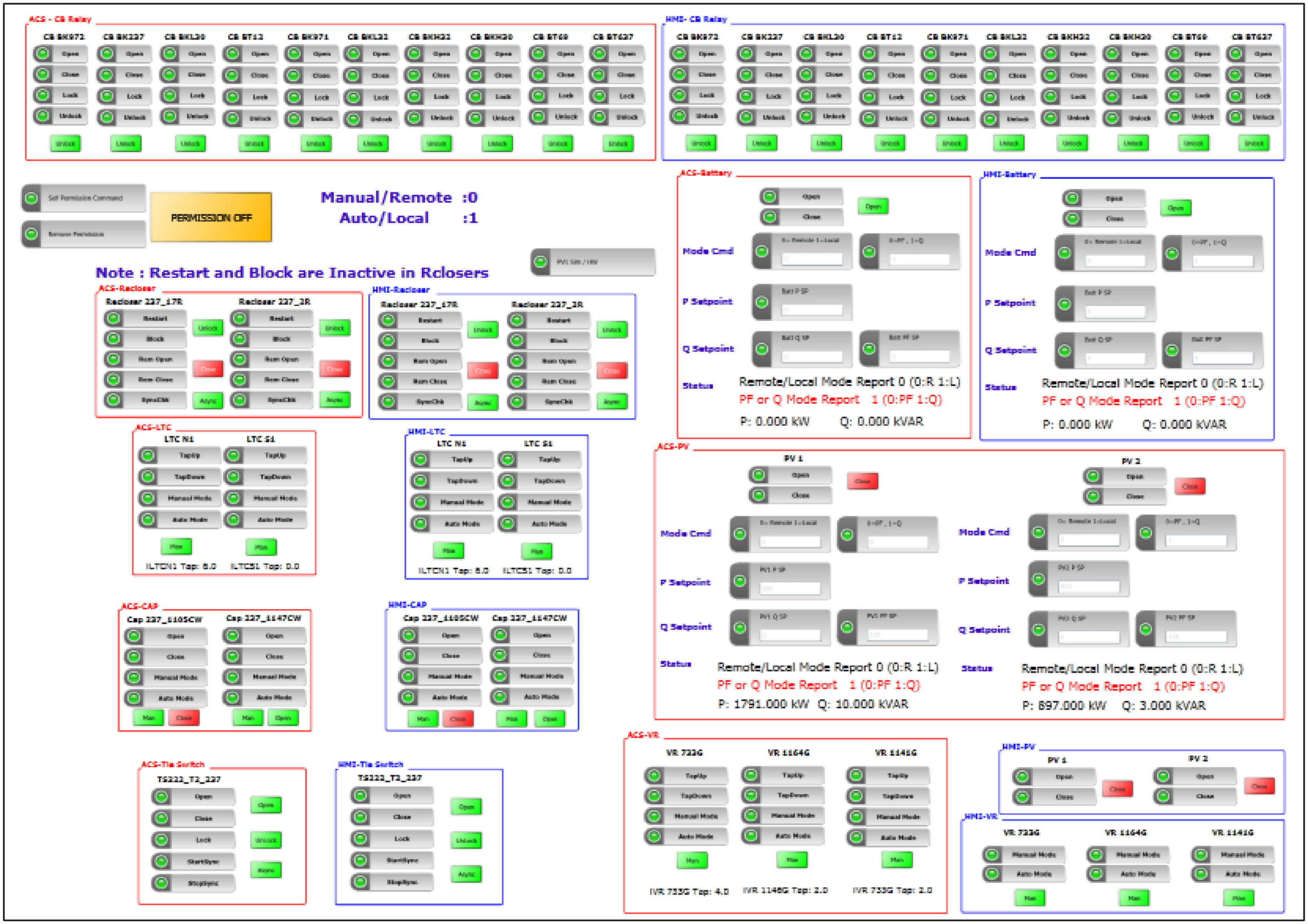
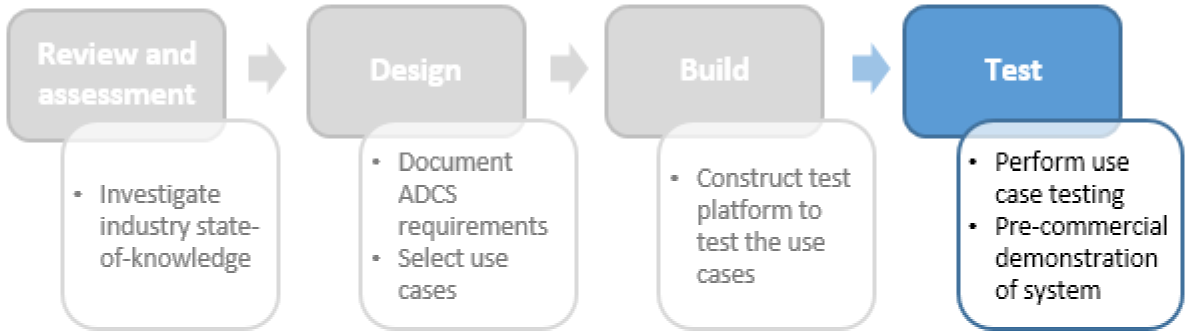


Figure 2-22. Monitoring the DER setpoints and other settings in the local HMI of substation A.

2.4 Distributed control system pre-commercial demonstration



Testing of the system was implemented in three separate phases:

- Factory acceptance testing of a simplified model consisting on a single circuit with limited hardware-in-the-loop
- Factory acceptance testing of a comprehensive model using two circuits with additional hardware-in-the-loop
- Site acceptance testing of the complete model using two circuits with extensive hardware-in-the-loop, including an actual Battery Energy Storage System and smart PV inverter.

An interesting side-note is that for much of the test platform development and initial testing, the Master Controller was physically located in Atlanta, GA at the headquarters of ACS, the SCADA platform provider, while the substation controllers, digital simulator and the hardware-in-the-loop IEDs were located in Toronto, ON at the Canadian office of Quanta Technology. The controllers were networked together over the public internet and system testing was performed on this distributed configuration for an extended period of time. The first time the master controller was in the same physical location as the rest of the equipment was when it was integrated into the hardware rack in the Toronto office just prior to shipping the equipment to ITF for the SAT.

2.4.1 Test plans

Test plans were created for each of the test phases. The test plan incorporated a comprehensive set of tests to evaluate the performance of the proposed automated distributed control system and to contrast it with a conventional control scheme.

Two baseline systems were used for comparison:

- Baseline System 1: system with no DER and local/automatic controls for individual devices (with no coordination) in the field.
- Baseline System 2: system with DER (penetration depends on the test case) and local/automatic controls for individual devices (with no coordination) in the field.

The test cases and performance comparisons for each of the use cases is discussed in sections 2.4.4.2 to 2.4.6.2.

2.4.2 Data collection

In order to analyze the performance of the system, it was essential to collect measurements, statuses, setpoints, and commands during each test. Therefore, the project considered two separate paths for archiving test data with an acceptable resolution:

1. The master controller was continuously saving a list of desired parameters during each test; the variables of interest included but were not limited to bus voltages, breaker powers, switch statuses, DER outpour powers, tap changer position, voltage regulator tap position, Cap bank statuses, etc.
2. The PI historian interfaced with the test setup and archived all the analog and binary values reported from the system to the master controller. The digital simulator sent a comprehensive list of measurements and statuses to the master controller (and subsequently to the PI). The time resolution for archiving these data was adjustable in PI, and was set to a time resolution of 10 seconds, which was deemed sufficient for post-mortem data analysis.

In addition to these two paths, phasor measurement unit (PMU) measurement data were also able to be retrieved from the SynchroWave Central/Historian. These PMU measurements were mainly intended for monitoring purposes although they were also available for later extraction and analysis purposes if required.

2.4.3 Communications Tests

The purpose of this test category was to verify proper communications amongst various components of the test setup as a precondition for performing use case testing. As such, several tests were performed to verify communications between:

- Field (digital simulator or hardware device) and substation; and
- Substation and control center (master controller)

2.4.3.1 Field and Substation Communications

Table 2.12 provides a list of major tests executed (or steps taken) for verifying communications between field devices (digital simulator/hardware) and the substation controller.

Table 2.12. Communication test cases

Case#	Test Case	Description
1	IP/Port number verification	Ensure that digital simulator and Substation Controller could ping each other
2	Analogue input (measurements) reading by substation controller	Change the power flow of the circuit and verify that the changes were reflected in the HMI
3	Analogue output (setpoints) writing by substation controller	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they were applied correctly
4	Binary input (status) reading by substation controller	Change the status of switching devices and verify that the changes were reflected in the HMI
5	Binary output (commands) writing by substation controller	Send open/close command to switching devices (or issue tap up/down commands to the VR) and verify that it was applied properly

One of the screens created for the local HMIs provided a communications status overview. The absence of communications with any of the devices would be reflected in the screens and visible to the user. A sample screen is shown in Figure 2-23 below.

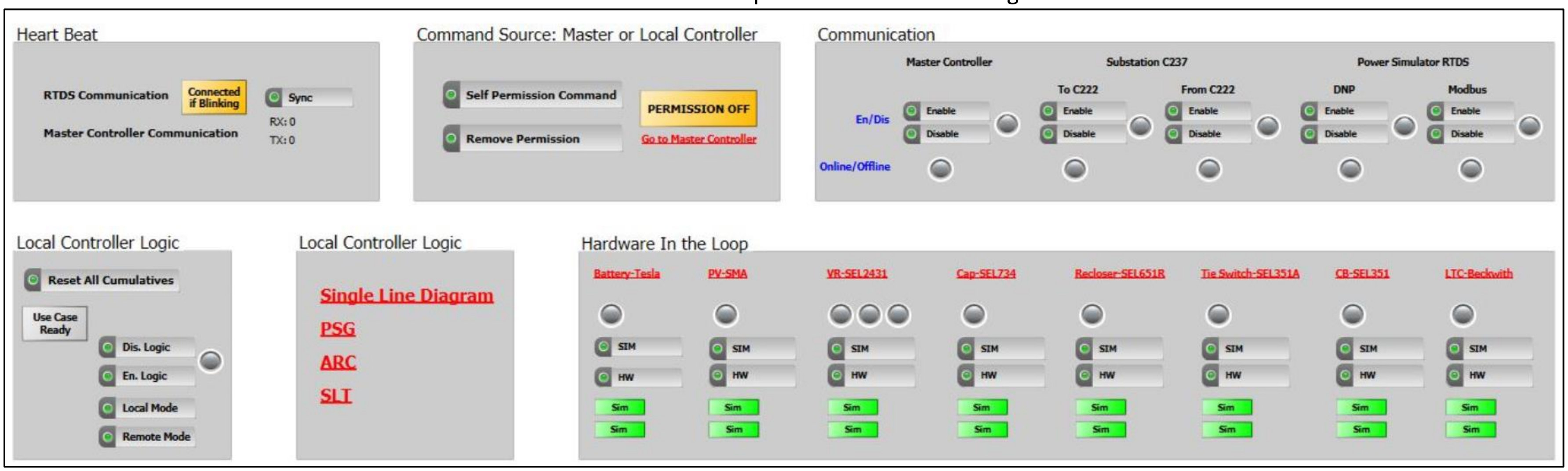


Figure 2-23. Communications testing – Communications status display on Local HMI of Substation A

As a part of communication tests, real and reactive power setpoints (P and Q) were sent from substation controller to the battery, and the battery response was confirmed. Figure 2-24 and Figure 2-25 shows the response of the battery to the following sequence of real and reactive power commands:

- Initially real and reactive powers of the battery were (almost) zero.
- First, real power setpoint of P_{SP}=550kW[7] was sent to the battery (Figure 2-24 (a))
- While P=550kW, a reactive power setpoint of Q_{SP}=–300kW was issued to the battery (Figure 2-25 (a))
- Then the battery was taken to the charging mode by P_{SP}=–500kW (Figure 2-24 (b))
- Finally, the reactive power setpoint of Q_{SP}=350kW was issued to the battery (Figure 2-25 (b))

(a) **(b)**

Figure 2-24. Communications testing - Response of the battery to P commands issued from the Local HMI

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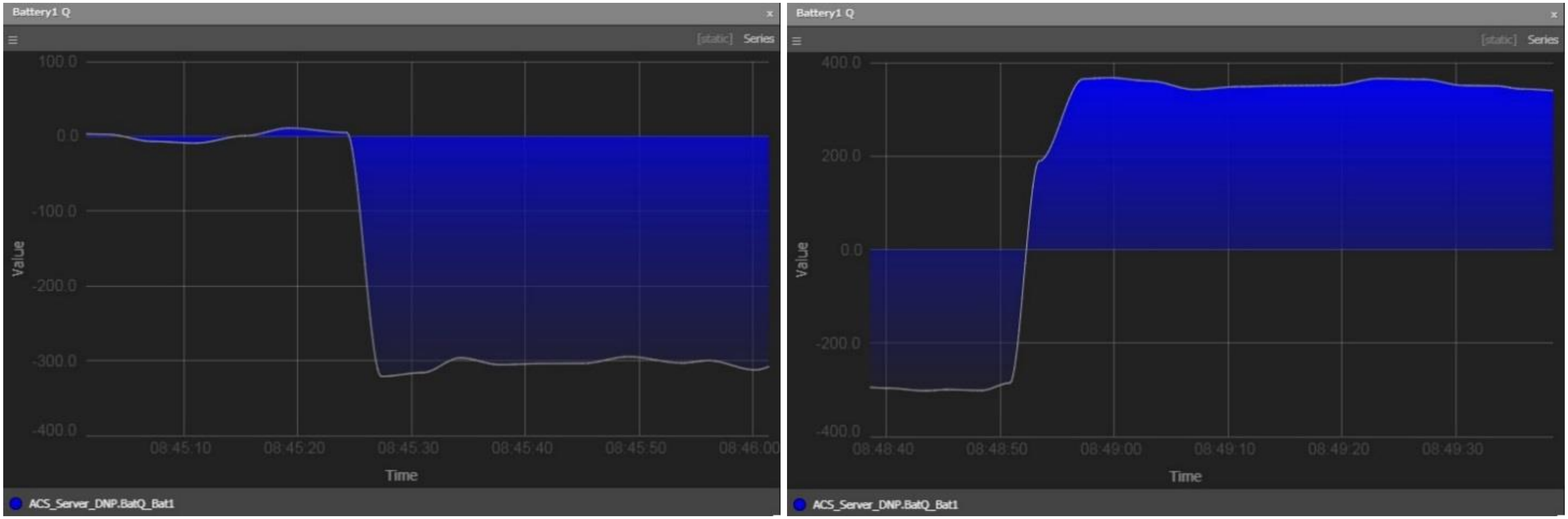
[7] A scaling factor of 10 was used to integrate a 200kW inverter as a 2MW battery energy storage system into the simulated power system.



(a) **(b)**

Figure 2-25. Communications testing - Response of the battery to Q commands issued from the Local HMI

2.4.3.2 Substation and control center communications

Several tests were executed to verify the DNP 3.0 communications between the substation controller and the master controller. Table 2.13 lists the major test cases used to verify proper establishment of this communication.

Table 2.13. Substation and control center communications test cases

Case#	Test Case	Description
1	IP/Port number verification	Ensure that substation controller and master controller could ping each other
2	Analogue input (measurements) reading by master controller	Change the power flow of the circuit and verify that the changes were reflected in the HMI
3	Analogue output (setpoints) writing by master controller	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they were applied correctly
4	Binary input (status) reading by master controller	Change the status of switching devices and verify that the changes were reflected in the HMI
5	Binary output (commands) writing by master controller	Send open/close command to switching devices (or tap up/down a VR) and verify that it was applied properly

All setpoints and commands were tested to ensure proper control actions would be taken when needed. Figure 2-26 and Figure 2-27 show snapshots of the master controller screens for the steady-state conditions of Baseline System 1.

Figure 2-26. Snapshot of the master controller HMI (CCR1 – Baseline System 1)

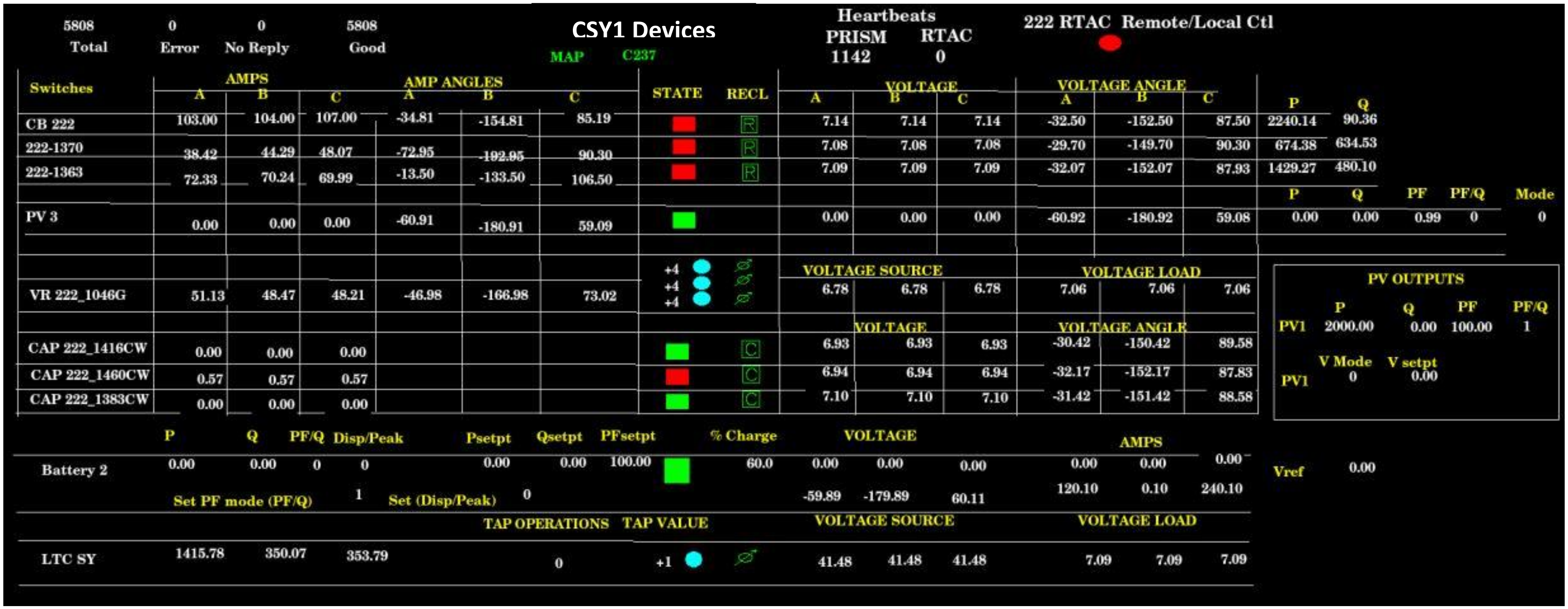
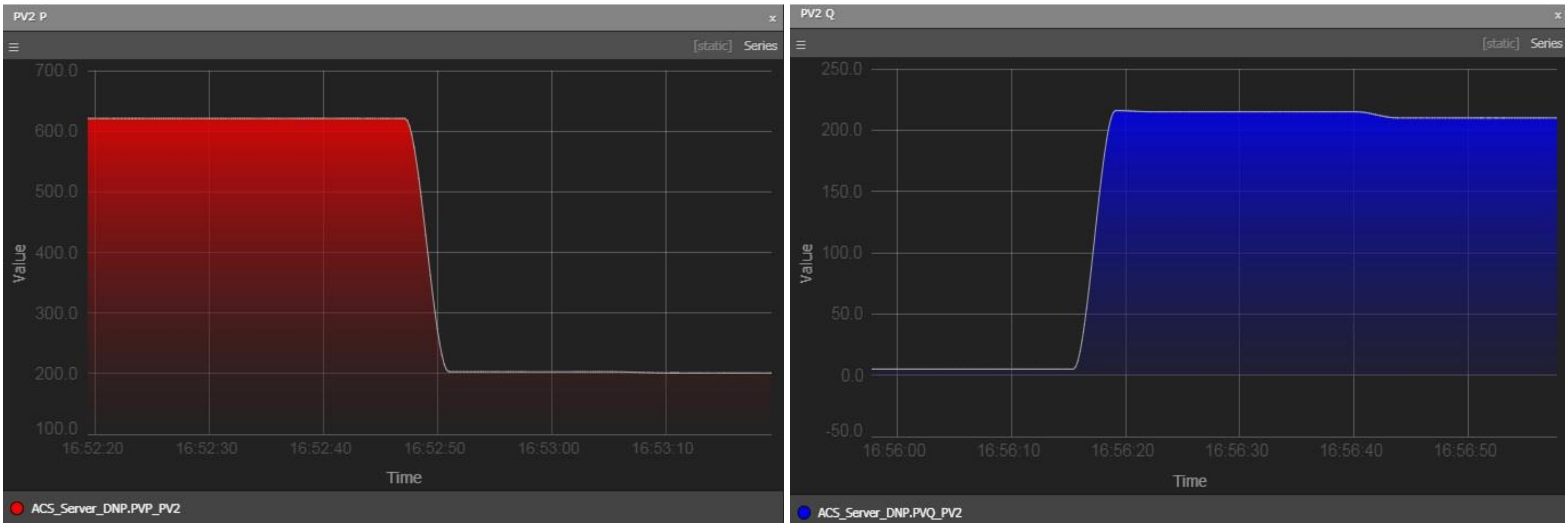


Figure 2-27. Snapshot of the master controller HMI (CSY1 – Baseline System 1)

A set of curtailment and reactive commands were sent from the master controller to the SMA PV inverter in the field, and the inverter response was confirmed. Figure 2-28 shows the response of the SMA inverter to the following set of commands:

- Initially real and reactive powers of the inverter were 620kW[8] and zero, respectively.
- Real power of the inverter was curtailed to P_{SP}=200kW.
- While P=200kW, a reactive power setpoint of Q_{SP}=200kW was issued to the inverter.

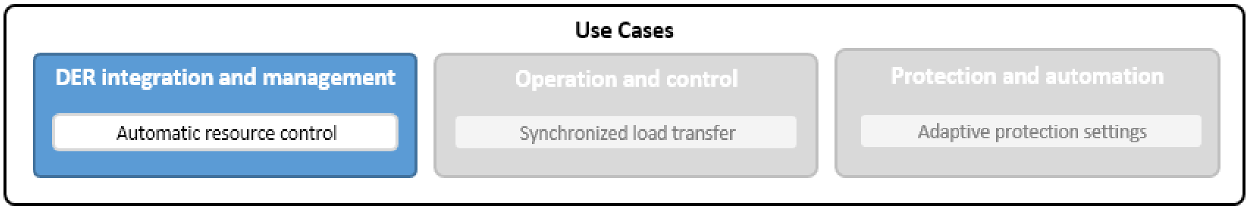


Active Power (P) **Reactive Power (Q)**

Figure 2-28. Response of the PV inverter to P and Q commands issued from the master controller

[8] A scaling factor of 100 is used to integrate a SMA 10kW inverter as a 1MW PV system into the simulated power system.

2.4.4 Use case 1: Automatic Resource Control



The main objective of the Automatic Resource Control (ARC) implemented on the test system was to achieve the optimal combination of LTC, VR, Cap Bank settings and output powers of controllable DERs in order to improve operating conditions such as voltage profile, losses, load balance, and overloading conditions, and/or to prevent excessive reverse power flow from local distributed generation (e.g., PV generation) by limiting the maximum DER generation.

ARC benefits were accomplished by minimizing the average voltage of all nodes and injection points at the point of common coupling to the feeder, while maintaining 'end of line' voltages within acceptable operating limits. ARC produced a solution, which minimized energy consumption and maximized energy transfer at the lowest cost.

The ARC application utilized two control blocks for its proper performance; these were:

- Feeder Injection Test (FIT) tool; and
- Near-Real-Time Power Flow (NRTPF) model

Access to real-time SCADA measurements was critical for the accurate performance of the ARC function. The Feeder Injection Test (FIT) tool determined whether there were circuit performance violation(s) that could not be corrected by automatic resource control. In the event that violations were detected, FIT used real-time field/SCADA data, load/generation forecast results, and the Near-Real-Time Power Flow Model to determine if the circuit violation could be resolved by resource control (DER dispatch and LTC/VR/Cap control).

The ARC function first located and identified LTCs, VRs, Cap banks, and DER assets. Then, the candidate ARC devices/inverters were identified to modify their settings/setpoints. Based on the results of the power flow analysis (NRTPF model), optimal control settings and/or setpoints were calculated and issued to the ARC devices and/or inverter assets to ensure desired system performance.

The ARC application performed the following functions:

- Utilized the results of the FIT tool or an operator request to trigger further action;
- Acquired information about
  - LTC settings and control modes;
  - VR settings and control modes;
  - Cap Bank controller settings and modes;
  - DER power/energy settings; and
  - Current status of ARC devise/inverters.

- Determined if the change in LTC/VR/Cap Bank setting or DER dispatch (ARC function) could improve system conditions (voltage quality, loading, etc.);
- Identified the ARC assets or DERs that needed to modify their settings/setpoints for optimal system performance;
- Calculated optimum settings/setpoint for selected devices/DERs;
- Sent the settings/setpoints to target ARC devices/DERs via DERMS (or another higher-level control platform);
- Received confirmation from ARC devices/DERs on the receipt of settings/setpoints and their activation;
- Triggered alarms if:
  - Automatic resource control could not resolve the circuit violation;
  - Automatic resource control could not be accomplished due to the current state of ARC devices/DERs or other limitations;
  - Communication network had failed;
  - Communication with the target ARC device/DER had failed; and
  - The target device/DER was not responded properly to the setting/setpoint change command.
- Sent ARC confirmation signal to Distributed Energy Resource Management System (DERMS) or Distribution Management System (DMS) indicating that the device/DER setpoints/settings were changed.

Three-pass optimization

ARC used a three-pass iterative approach to control from ‘course’ control to ‘fine’ control.

1. The first pass minimized the var losses by controlling the feeder capacitors.
2. The second pass flattened the line drop voltage after the impact of the capacitor switching in the first layer was calculated. The second pass controlled the LTC and voltage regulators.
3. The third pass applied fine control of the voltage based on the ability of the inverter to affect the voltage at the point of common coupling / injection points. Many smart Inverters can be issued a voltage set point directly from ARC based on an optimum target calculated for the entire scope of the feeder. Other inverters offer real and reactive power (P/Q) set-point control which is used to drive an optimum voltage at the point of common coupling (PCC).

Table 2.14 provides more details on the three-pass optimization layers of the ARC use case. The sequence diagram for the ARC application is also shown in Figure 2-29.

Table 2.14. Three-pass optimization

Pass	Characteristics
Pass 1: Load flow optimized var minimization	ARC ran an Unbalanced Distribution Load Flow optimization in order to determine an optimum control strategy and to avoid control ‘hunting’. The load flow was run in real-time to determine reactive power requirements at each injection point and capacitor bank location for the entire feeder. If a significant amount of lagging reactive power flow was observed on the feeder at various nodes, the reactive contribution provided by the capacitor bank(s) needed to

Pass	Characteristics
	be engaged. Likewise, if there was a large amount of leading reactive power flow on the feeder breaker, the capacitor bank(s) needed to be decoupled from the feeder. The decision was made through a series of load flow calculations. To verify if a given capacitor operation violated any Voltage constraints, the changes in Voltage and power factor were calculated for the entire feeder considering the effect of the capacitor operation. The analysis considered the operable capacitors on the feeder which were located first by topology tracing from the feeder breaker downstream. Feeder loads were estimated by Load estimator using a combination of static load curves of load behavior modified by real-time measurements of actual to calculate Voltage, branch flows, and power factors. The branch flows at device locations were analyzed so that the capacitor banks were sorted in descending order based on their branch reactive power flows. The capacitor with the largest branch reactive power was selected as a control candidate. Its impact on feeder Voltages was calculated and checked against the limits and if no limit was exceeded, a control command was issued to operate this capacitor bank. If any constraint was violated, the capacitor bank would be passed over and the next capacitor processed. The above process was repeated until distribution loss was minimized or no capacitor was available for control.
Pass 2: Load flow optimized voltage reduction	The second step in the control cycle after the capacitor settings were made was to evaluate the feeder Voltage. When capacitors are added they raise Voltages contrary to the objective of Voltage reduction and increase energy usage. This mandated the need to coordinate kvar control with Voltage control. Once capacitor bank statuses were determined, a load flow calculation was performed to find the highest and lowest Voltages in the feeder assuming all devices took the expected control actions (either on or off). The Voltage regulation optimization which includes down line regulators was managed using a layer approach starting from the source. Voltage regulators on each phase were adjusted based on the Voltages on the other two phases to achieve balanced three phase Voltages. The solution ensured that no end of line Voltage violations took place. The regulator settings were sent out in steps as ARC verified the effect of the control action. Typically, the substation LTC is set to automatic mode which makes changes at the bus level thereby affecting all feeders. Based on the real-time transformer data ARC would operate dynamically to adjust the optimum LTC setting. If the substation LTC couldn't be adjusted or if it was set manually, it was desirable to know the optimum setting. A bus Voltage target set point could be entered, which ARC will provide a recommended setting either in advisory mode or through a control point if it is available. In summary, the optimum control settings for capacitors regulators and LTCs are adjusted such that the lowest Voltage is maintained above the low Voltage limit.
Pass 3: Load flow optimized voltage regulation	After the regulator tap settings were implemented, the optimum calculated Voltage at the PCC was assigned as a set point to the PV smart inverters. The inverters would then assign the necessary P/Q to maintain the assigned Voltage. In the event that inverters were not "smart", the ARC had the ability to set the P & Q set points to achieve the desired Voltage at the PCC.

Pass	Characteristics
	If an emergency limit was exceeded, for example due to unexpected load switching from one feeder to another, the ARC would close or open capacitors as necessary to reduce the violation before altering the regulator settings.

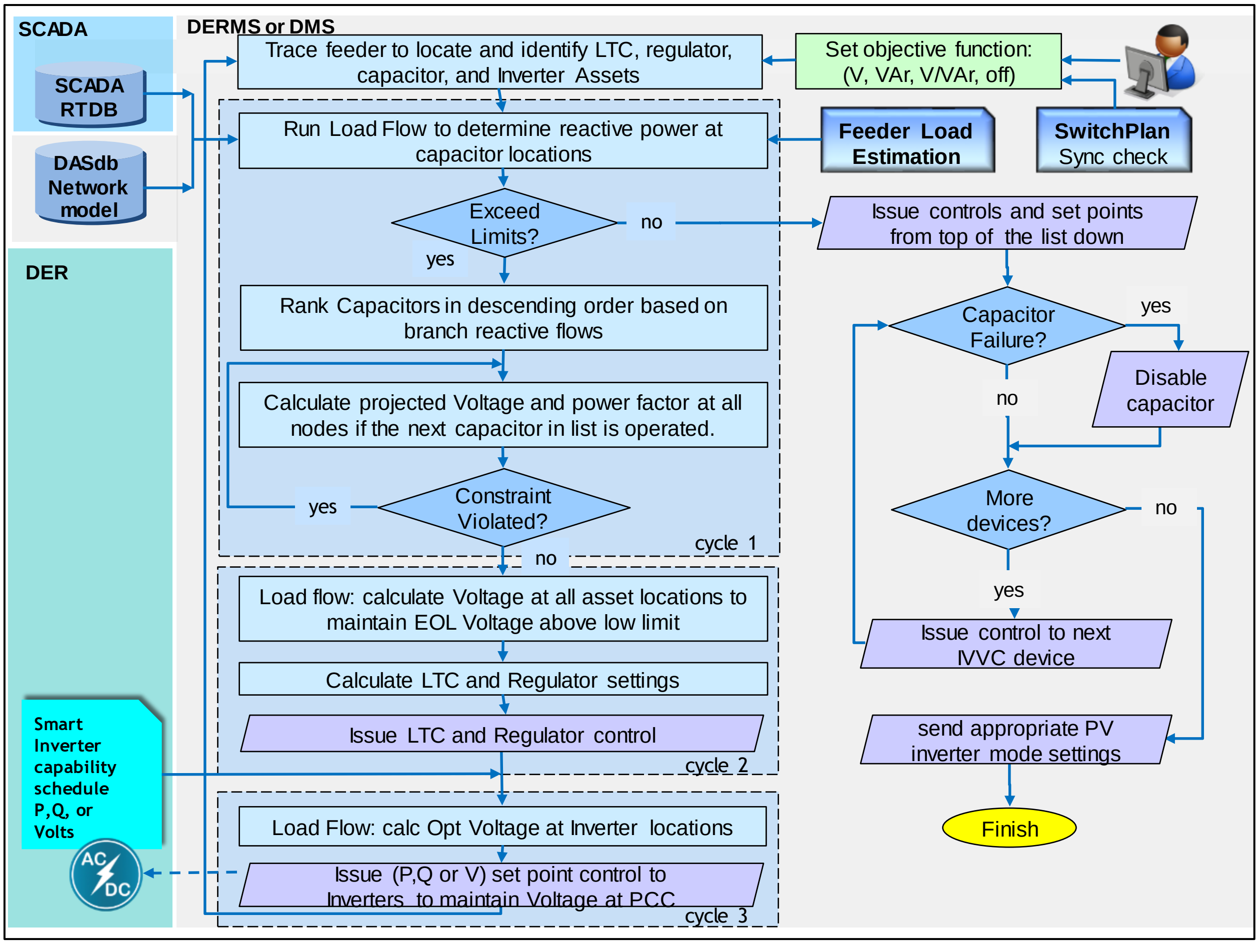


Figure 2-29. ARC logic control of the network devices and DER

2.4.4.1 Performance criteria

The following criteria were used to evaluate successful operation of the control system for ARC use cases:

- Voltage profile: standard deviation and out-of-range values/durations were used to examine the performance of the control function.
- Power loss (P_{loss}): reduced power loss was considered as one of the objectives of the central ARC. The following equation was used to calculate power loss at the substation level

$$P_{loss} = P_{grid} + P_{DER} - P_{loads}$$

- DER involvement/contribution: this was evaluated based on the power drawn from the grid or substation transformer (P_{grid}). Higher DER involvement was equivalent to less power drawn from the grid. It is noted that DER reactive power contribution to voltage improvement was preferred over the utilization of other assets.

- Power factor at the circuit level ($pf = \cos[tan^{-1}(Q_{grid}/P_{grid})]$: improved power factor was considered as one of the objectives of the central ARC.
- Number of capacitor bank (Cap bank) operation (n_{cap}): optimal operation of Cap banks was one of the objectives of the ARC
- Number of voltage regulator (VR) operation (n_{VR}):optimal operation of voltage regulators was one of the objectives of the ARC
- Number of load tap changer (LTC) operation (n_{LTC}):optimal operation of load tap changers was one of the objectives of the ARC

Table 2.15 provides a summary of the factors used for the ARC evaluation.

Table 2.15. Performance criteria for ARC use case

Criteria	Parameter	Remark
Voltage profile	ΔV_P, ΔV_t, σ	Out-of-range value, Out-of-range duration, Standard deviation
Power loss	P_{loss}	
DER involvement	P_{grid}, P_{DERs}, Q_{DERs}	DER and grid power values
Power factor at circuit level	$P_{CB-feeder}$, $Q_{CB-feeder}$	
Number of Cap bank operation	n_{Cap}	
Number of voltage regulator operation	n_{VR}	
Number of LTC operation	n_{LTC}	

2.4.4.2 Test Results

The purpose of this test category was to verify that master controller and substation controllers were able to automatically control the system resources (i.e., controllable assets and DERs) in order to maintain the operating parameters of the system within the acceptable ranges specified by SDG&E. Several test cases were considered in this use case to ensure proper operation of the ARC function under various load, generation, and system operating conditions. Table 2.16 lists the major test cases that were run. The test cases were selected to enable the evaluation of system performance under three control scenarios:

- Scenario 1 (CS 1): Only device local controls were in place (no remote control available)
- Scenario 2 (CS 2): Master controller was in charge of resource control
- Scenario 3 (CS 3): Substation controller was in charge of resource control

The location of the devices referenced in the Test Condition column in Table 2.16 are highlighted in the figure below.

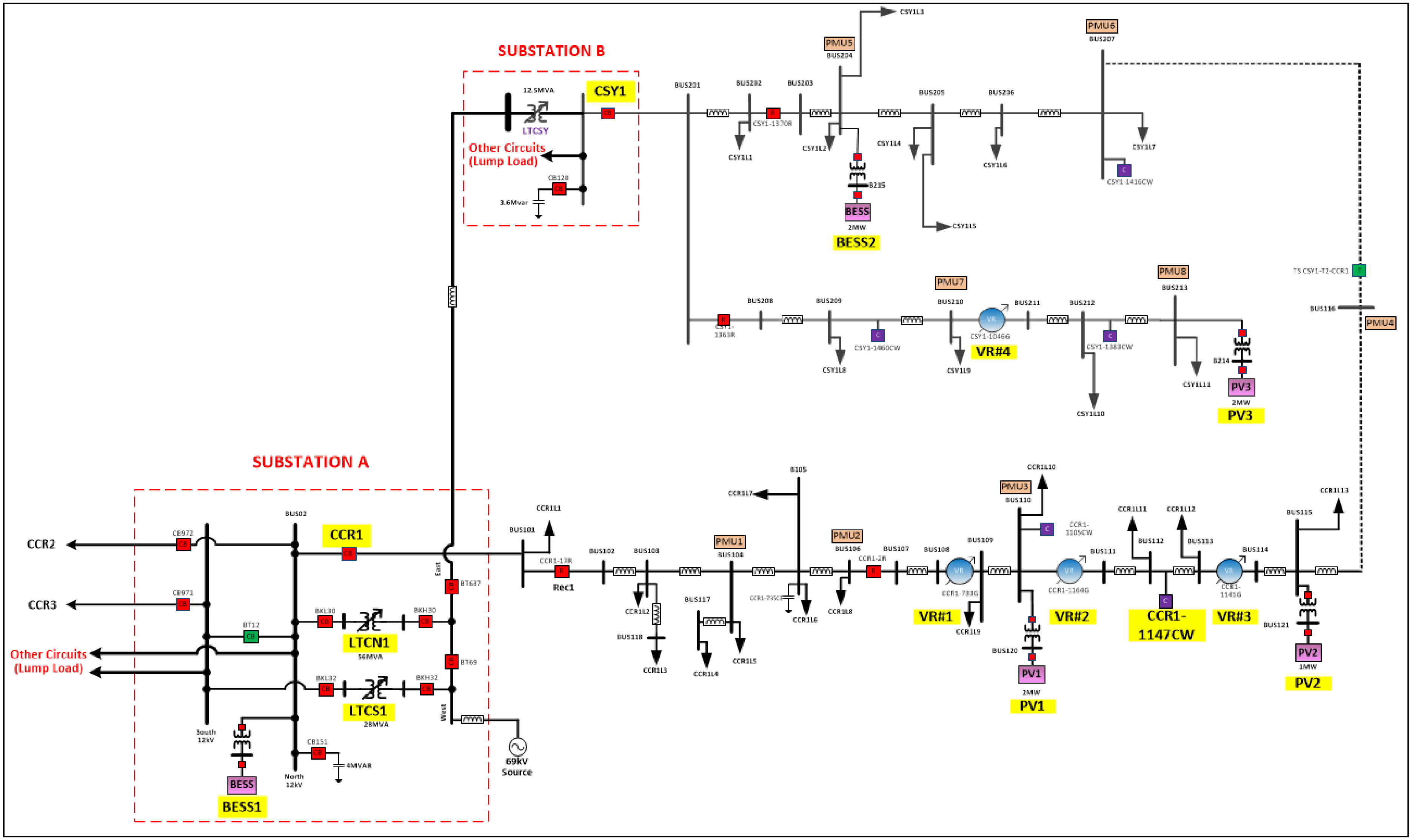


Figure 2-30. Identification of devices referenced in use case 1 test cases

It is worth mentioning that when the substation control assumes responsibility for controlling resources, it would first change the control mode of all controllable assets to “Local”. Then, based on the level of control that the substation controller was able to offer, it would change the control mode of corresponding devices to “Remote” in order to remotely control them. The control functions of the substation controller depended on various parameters including utility requirements, controller programming capability, controller communication capability, etc. For the purpose of this study, the substation controller mainly utilized DERs to improve system operating conditions and, thus, had limited control functionality when compared to the master controller.

Table 2.16. ARC Test Cases

Case#	Test Conditions	Description	Remark
1.1	CCR1: Pload=7.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	High load (fix), no DER	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)
1.2	CCR1: Pload=7.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	High load (fix), no DER	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.3	CCR1: Pload=2.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=2.3MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Low load (fix), no DER	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)
1.4	CCR1: Pload=2.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=2.3MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Low load (fix), no DER	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.5	CCR1: Pload=7.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), Low PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.6	CCR1: Pload=7.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), Low PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.

Case#	Test Conditions	Description	Remark
1.7	CCR1: Pload=7.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), Low PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)
1.8	Case 1.5, trip CCR1-1147CW (e.g., fault) after the system gets to the steady state condition.	High load (fix), Low PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.9	Case 1.6, tripCCR1-1147CW (e.g., fault) after the system gets to the steady state condition.	High load (fix), Low PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.10	CCR1: Pload=7.2MW, PPV1=1.8MW, PPV2=0.9MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=1.8MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.11	CCR1: Pload=7.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=1.8MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), High PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.12	CCR1: Pload=7.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=1.8MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), High PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)
1.13	Case 1.10 (PBESS1= PBESS2=0), trip PV 1 after the system gets to the steady state condition.	High load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.14	Case 1.11 (PBESS1= PBESS2=0), trip PV 1 after the system gets to the steady state condition.	High load (fix), High PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.15	CCR1: Pload=2.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), Low PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.16	CCR1: Pload=2.2MW , PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), Low PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.17	CCR1: Pload=2.2MW , PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), Low PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)

Case#	Test Conditions	Description	Remark
1.18	CCR1: Pload=2.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=1.8MW , PBESS2=0.5MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.19	CCR1: Pload=2.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1.8MW , PBESS2=0MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.20	CCR1: Pload=2.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1.8MW , PBESS2=0.5MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)
1.21	Case 1.15, trip PVs after the system gets to the steady state condition.	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.22	Case 1.16, trip PVs after the system gets to the steady state condition.	Low load (fix), High PV (fix)	Master controller is responsible to take actions through ARC/IVVC algorithm.
1.23	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	High load profile (real), High PV profile (real)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.24	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	High load profile (real), High PV profile (real)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.25	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Low load profile (real), Low PV profile (real)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.26	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Low load profile (real), Low PV profile (real)	Master controller was responsible to take actions through ARC/IVVC algorithm.

For the sale of brevity, only the results of a selected number of test cases are detailed in the following paragraphs. The test data and analysis results for all cases are available in Appendix A. For the selected test cases, this report provides a comparative analysis of test results for all control scenarios (*i.e.*, Control Scenarios 1, 2, and 3) to provide the reader with a better understanding of the advantages and disadvantages associated with each control scenario.

2.4.4.3 High load and high PV condition

In this subsection, the performance of the control system under high load and high PV profiles were examined. To that end, while the system was operating under high-load condition, the PV generation was suddenly increased to study the system reaction to such a drastic change. It is acknowledged that the likelihood of such an event occurring in the real world is slight; however, the goal was to compare system performance for such extreme cases under various control scenarios. The three test cases selected for further analysis were:

- Test Case 1.10 – All controllable devices were in Local/Auto mode, i.e. neither master controller nor substation controller active (CS 1).
- Test Case 1.11 – Master controller was responsible to take actions through ARC algorithm (CS 2).
- Test Case 1.12 – Substation controller was responsible to take actions either because permission had been granted by the master controller, or communications had been lost to the latter (CS 3).

2.4.4.3.1 Voltage profile

Figure 2-31(a) through Figure 2-31(c) show the voltage profile of circuit CCR1 for the test case with high load and high PV generation under the three control scenarios described above. This report primarily focuses on the analysis of the results obtained for circuit CCR1 because this circuit included all hardware devices including relays, voltage regulators, load tap changes and DERs. As such, the results of circuit CCR1 were more realistic, incorporating the inherent response time of actual controllable devices in the field. Similar results were also collected and analyzed for the fully simulated circuit CSY1, but are not discussed further in this report – they are however available as an electronic addendum to this report.

In Figure 2-31, three bus voltages were selected to represent the voltage profile of the feeder during the test. Voltage of Bus 103 represented the voltage at beginning of the feeder, voltage of Bus 110 indicated the voltage at middle of the feeder, and voltage of Bus 115 represented the end of the line (EOL) voltage (see Figure 2-13 to view the test system SLD). Comparing the voltage profiles for all three control scenarios[9], one can observe that the control response time was considerably faster in control scenario 2 (CS 2). In addition, both the voltage out-of-range value and voltage out-of-range duration were smaller when the master controller was in charge (CS 2). The color code used in Figure 2-31 for different voltage ranges is as follows:

- Green: Permissible range (system was allowed to work in this range for extended period of time)
- Orange: Moderate range (system was allowed to work in this range for certain time period – several minutes)
- Red: Excessive range (system was allowed to work in this range for a short period of time – several seconds)

A summary of main parameters related to the system voltage performance is presented in Table 2.17. The table shows that the majority of voltage-related criteria are improved when the master controller is operating. Moreover, although the performance of the system in control scenario 3 was not as good as

[9] A comprehensive set of data (with 10s resolution) was extracted from PI historian for analysis.

control scenario 2, it was still better than control scenario 1. It is worth noting that due to the location of PV systems, the voltage of the feeder end experienced a greater increase.

Table 2.17. Voltage-related criteria for three control scenarios (high load, high PV case)

Parameter		Value		
		CS 1	CS 2	CS 3
Maximum voltage magnitude (rms)		8.04kV (1.16pu)	7.44kV (1.074pu)	7.67kV (1.107pu)
Maximum out-of-range value with respect to maximum allowable voltage (rms)		765.4V (0.11pu)	165.4V (0.024pu)	395.3V (0.057pu)
Out-of-range duration (seconds)		115	25	80
Standard deviation	Bus 103 (beginning)	0.02412	0.01075	0.02135
	Bus 110 (middle)	0.18041	0.09328	0.19340
	Bus 115 (EOL)	0.40579	0.12152	0.37322
Average	Bus 103 (beginning)	7.096	7.078	7.044
	Bus 110 (middle)	7.046	7.088	7.037
	Bus 115 (EOL)	7.251	7.095	6.991

Figure 2-32 and Figure 2-33 show the voltage profile along the both tested circuits (*i.e.*, CCR1 and CSY1) at the steady-state condition subsequent to the test. As can be observed in these figures, under CS 2, the voltage profile of both circuits are more flat which is desirable. Further, the steady-state average voltage value is lower under CS 2 (while within the limit).

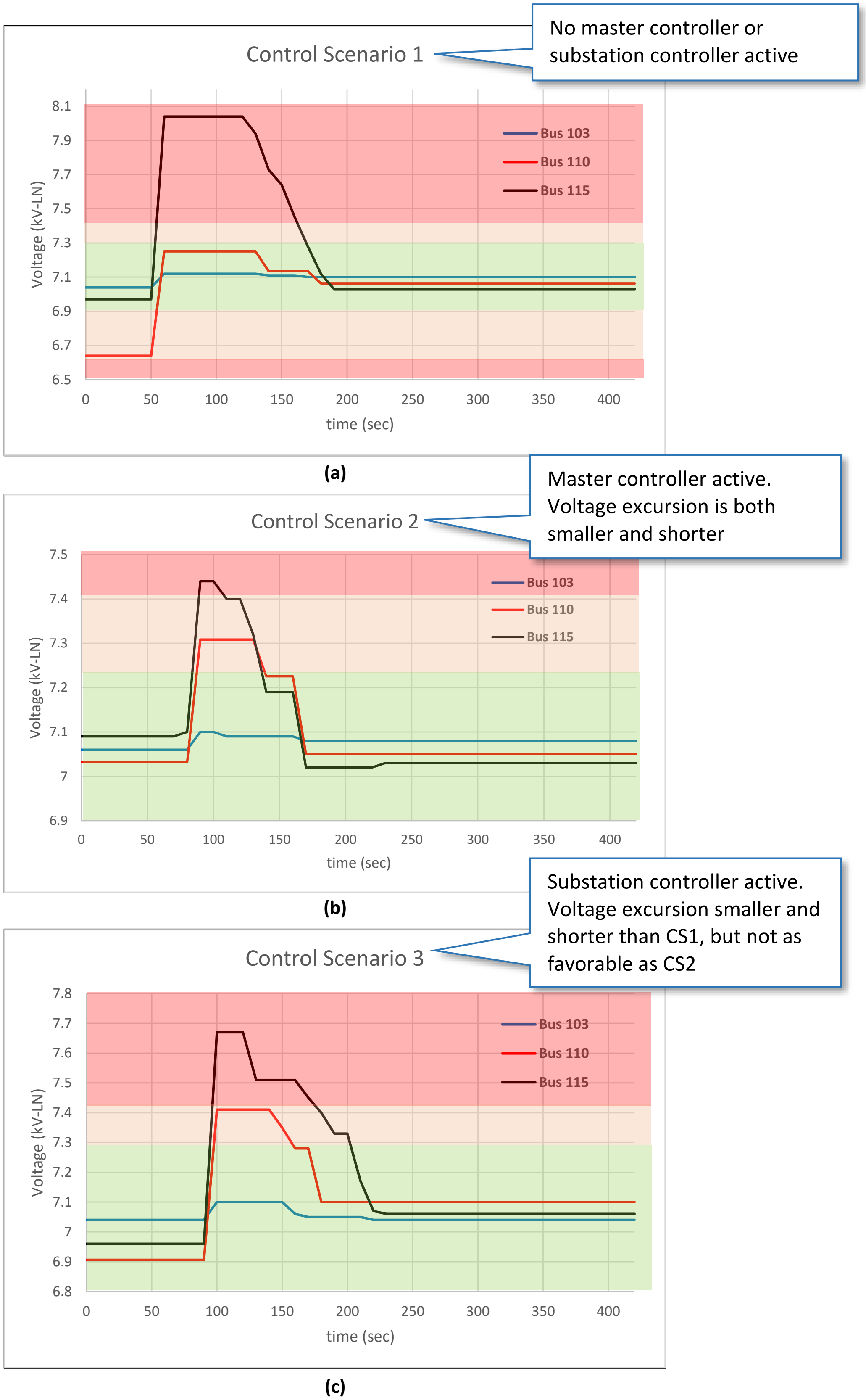


Figure 2-31. Voltage profile of circuit CCR1 for (a) Case 1.10, (b) Case 1.11, and (c) Case 1.12

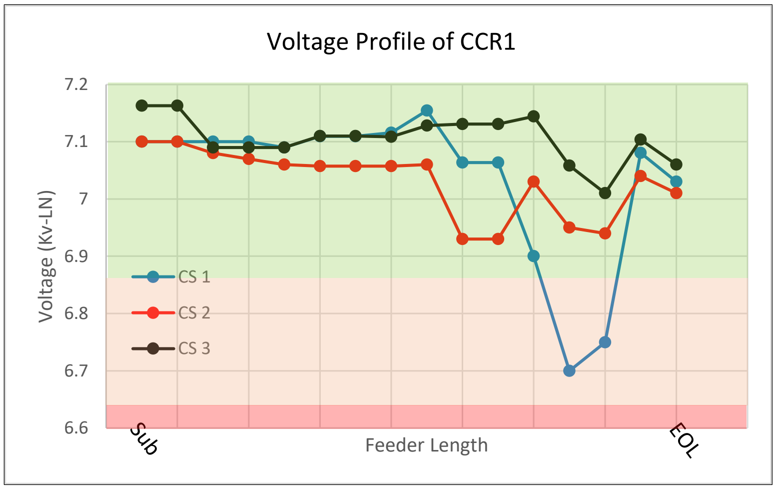
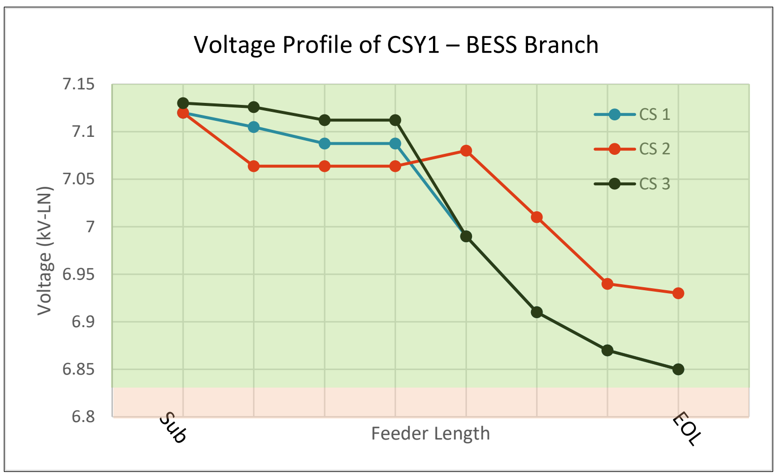
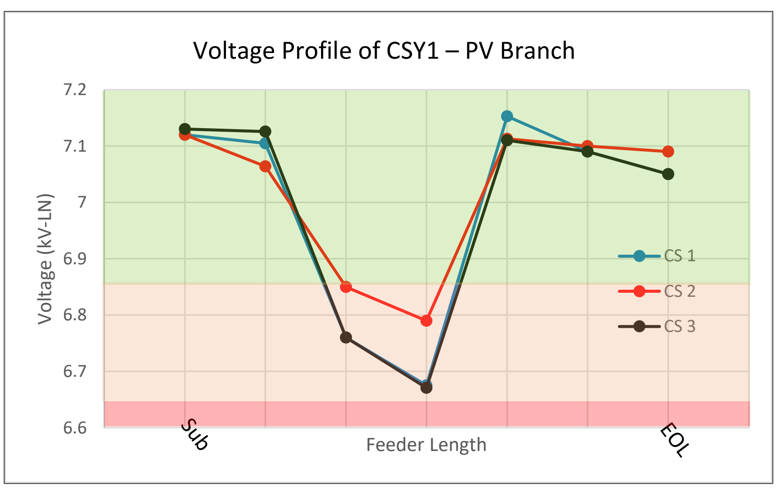


Figure 2-32. Steady-state voltage profile along circuit CCR1 under various control scenarios



(a)



(b)

Figure 2-33. Steady-state voltage profile along circuit CSY1 under various control scenarios: (a) BESS branch and (b) PV branch

2.4.4.3.2 Power losses

Figure 2-34 shows the power loss calculated for Substation "A" when the system operated under the three control scenarios (see Section 2.4.4.1 for power loss equation). As shown in this figure, the power loss generally decreased once the PV generation/injection started (at different instants); this is because some loads were supplied locally through PV systems (DERs). In addition, the amount of loss reduction was higher when the system operated under control scenario 2 and 3 (CS 2 and CS 3). This was mainly due to the fact that the master and substation controllers utilized more DERs to address system violations (as compared to local controllers). More specifically, battery energy storage systems made a greater contribution to the enhanced system performance (see Section 2.4.4.3.3), when the Master/Substation controller was in place.

Table 2.18 reports the power loss reduction for Substation A for the three control scenarios under study. As shown in this table, with no DERs, the total power loss was about 1.5MW (4.4% of the total substation load). However, with the DER contribution, the power loss decreased to 1.04MW, 0.77MW, and 0.86MW under CS 1, CS 2, and CS 3, respectively.

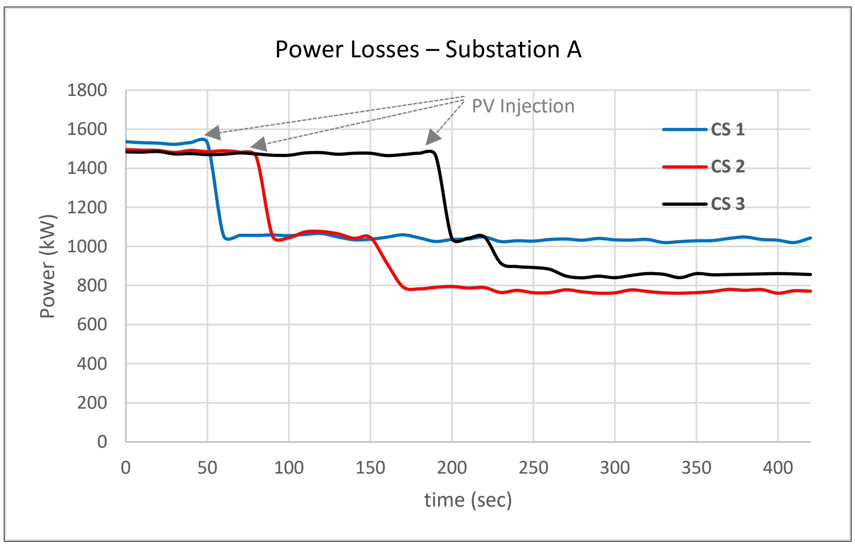


Figure 2-34. Power losses for Substation A (Cases 1.10, 1.11, and 1.12)

Table 2.18. Power loss reduction under three control scenarios

Control Scenario	Power Loss		
	Before	After	Enhancement
CS 1	1535.9kW (4.40%)	1043.5kW (3.04%)	1.36%
CS 2	1496.1kW (4.36%)	771.1kW (2.25%)	2.11%
CS 3	1493.9kW (4.36%)	856.4kW (2.50%)	1.86%

2.4.4.3.3 DER involvement/contribution

As the penetration of DERs increases, it is essential to utilize them effectively in the control process of distribution systems. Therefore, enhanced DER involvement was one of the key factors for the evaluation of the effectiveness of a control strategy. In this project, both DER output power and grid power were used as means to examine DER involvement. Figure 2-35 shows the grid power (only for Substation A) during the conducted test for each control scenario. As shown, the power drawn from the grid was reduced for CS 2 and CS 3, which is the main reason that the overall power loss decreased.

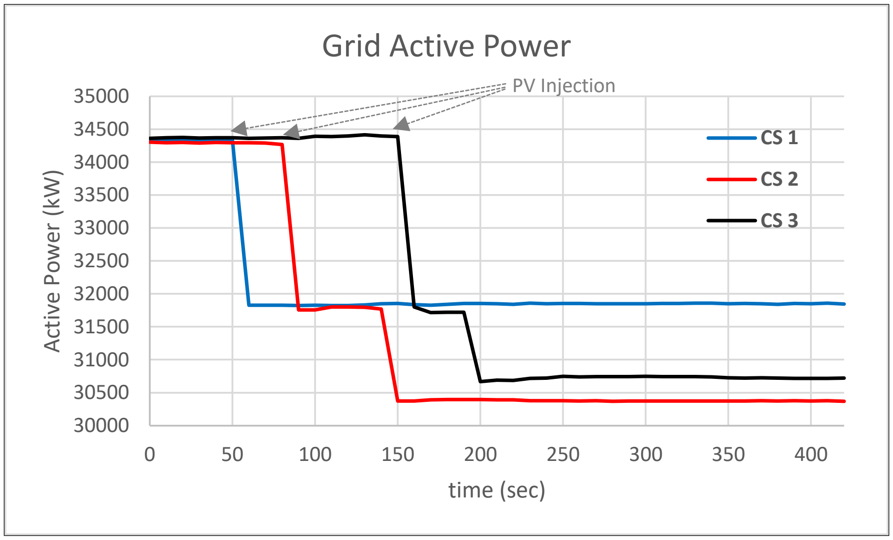


Figure 2-35. Grid power (Substation A) for high load, high PV case

The reactive power contributions (absorption) of DERs for each control scenario are plotted in Figure 2-36. Similarly, it is observed that DERs contributed more to the voltage correction under Control Scenarios 2 and 3. One interesting point is that, under CS 3, the DER reactive power contribution was even greater than that of CS2. This is because the substation controller was regulating the power factor (at the substation level) by controlling the reactive power of the substation battery (see BESS1 in Figure 2-40). This will be discussed further in the subsection that follows.

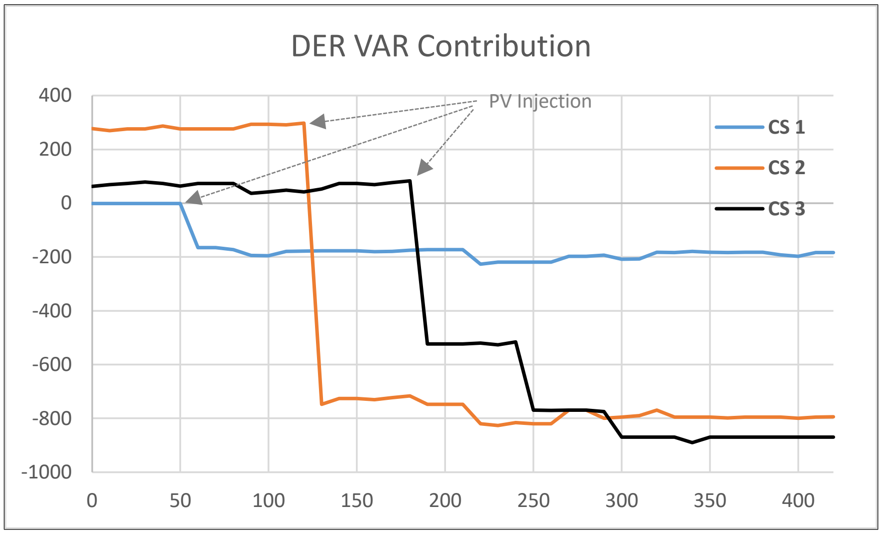


Figure 2-36. Reactive power contribution of DERs (Substation a) for high load, high PV case

2.4.4.3.4 Power factor

Figure 2-37 shows the reactive power flowing through Circuit Breaker CCR1 (CB CCR1 in Figure 2-13) for high load with high PV generation. Although the overall reactive power under normal condition was insignificant (both feeder capacitor banks located at circuit CCR1 are ON), the improvement under CS 2 and CS 3 was still observable. In other words, both master controller and substation controller tried to maintain power factor of the circuit at unity. This is evident in Figure 2-37 where the circuit reactive power was around zero under CS 2 and CS 3 (note the dash box). It should be noted that the accurate adjustment (fine tuning) of power factor is only achievable through the effective utilization/control of distributed energy resources (DERs).

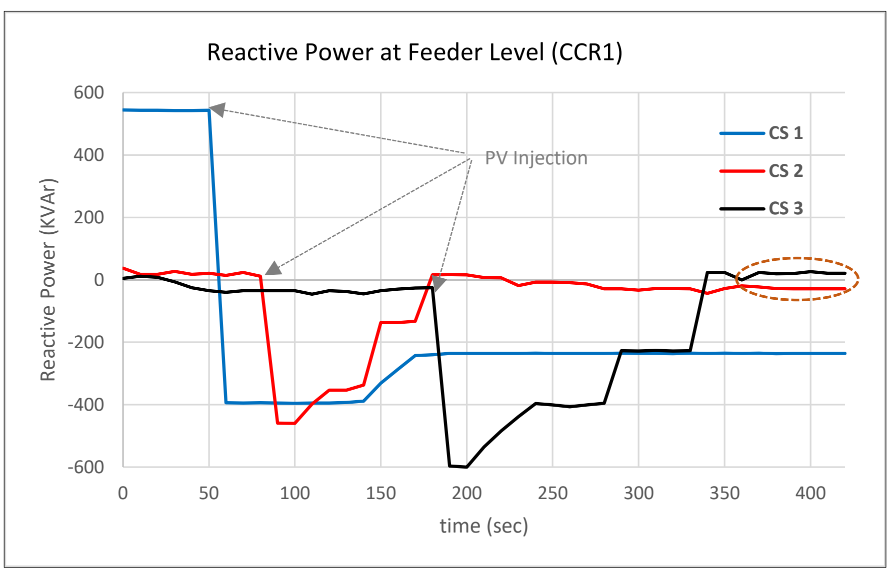


Figure 2-37. Reactive power at the feeder level for high load, high PV case

2.4.4.3.5 Asset operation

The last item studied for the evaluation of the ARC use case in the proposed control architecture was the number of operation of controllable assets. Ideally, it is expected that a central controller reduces the number of operation of Cap banks, voltage regulators, and tap changers. This should be achieved with efficient utilization of DERs for voltage regulation. However, it was observed that in some test cases there was no or little improvement in the cumulative number of asset operation. This was a result of the master controller trying to optimize the feeder voltage profile, which normally required more operations of some switchable devices.

Table 2.19 lists the cumulative numbers of operation for each controllable device employed in circuit CSY1 and circuit CCR1. Figure 2-38 identifies the location of each of these controllable devices on the SLD. For this test case, it was observed that the total operation of assets decreased under CS 2. This was mainly because of the enhanced DER involvement. It should be pointed out that, under CS 3, the total number of operation increased because: (i) substation controller tried to regulate voltage at best possible values and (ii) substation controller did not remotely control feeder capacitor banks (out of scope of this project).[10] It is also worth noting that the substation controller can provide the same functionality as the master controller, assuming proper logic capability and reliable communications with the field devices exist.

Table 2.19. Total number of operation of controllable devices (high load, high PV case)

Device	Total number of operation		
	CS1	CS2	CS3
Cap. CSY1_1383CW	1	1	0
Cap. CSY1_1416CW	0	0	0
Cap. CSY1_1460CW	0	0	0
Cap. CCR1_1105CW	0	0	0
Cap. CCR1_1147CW	0	0	0
VR CSY1-1046G_PhaseA	7	3	6
VR CSY1-1046G_PhaseB	8	3	6
VR CSY1-1046G_PhaseC	7	3	4
VR CCR1-733G_PhaseA	2	2	4
VR CCR1-733G_PhaseB	1	3	2
VR CCR1-733G_PhaseC	2	2	3
VR CCR1-1164G_PhaseA	5	4	4
VR CCR1-1164G_PhaseB	6	2	6
VR CCR1-1164G_PhaseC	4	3	5
VR CCR1-1141G_PhaseA	3	2	4

[10] Capacitor Banks have a minimum start times of 5 minutes (in Local mode) and, thus, before they get a chance to operate, the control of other devices may bring the voltage within the acceptable level (albeit at the price of higher operation number). However, the central controller can send close/trip commands to Cap Banks in Remote mode, knowing the operation history.

Device	Total number of operation		
	CS1	CS2	CS3
VR CCR1-1141G_PhaseB	3	3	5
VR CCR1-1141G_PhaseC	2	3	5
LTCN1	0	0	1
LTCSY	1	0	0
TOTAL	**52**	**34**	**55**

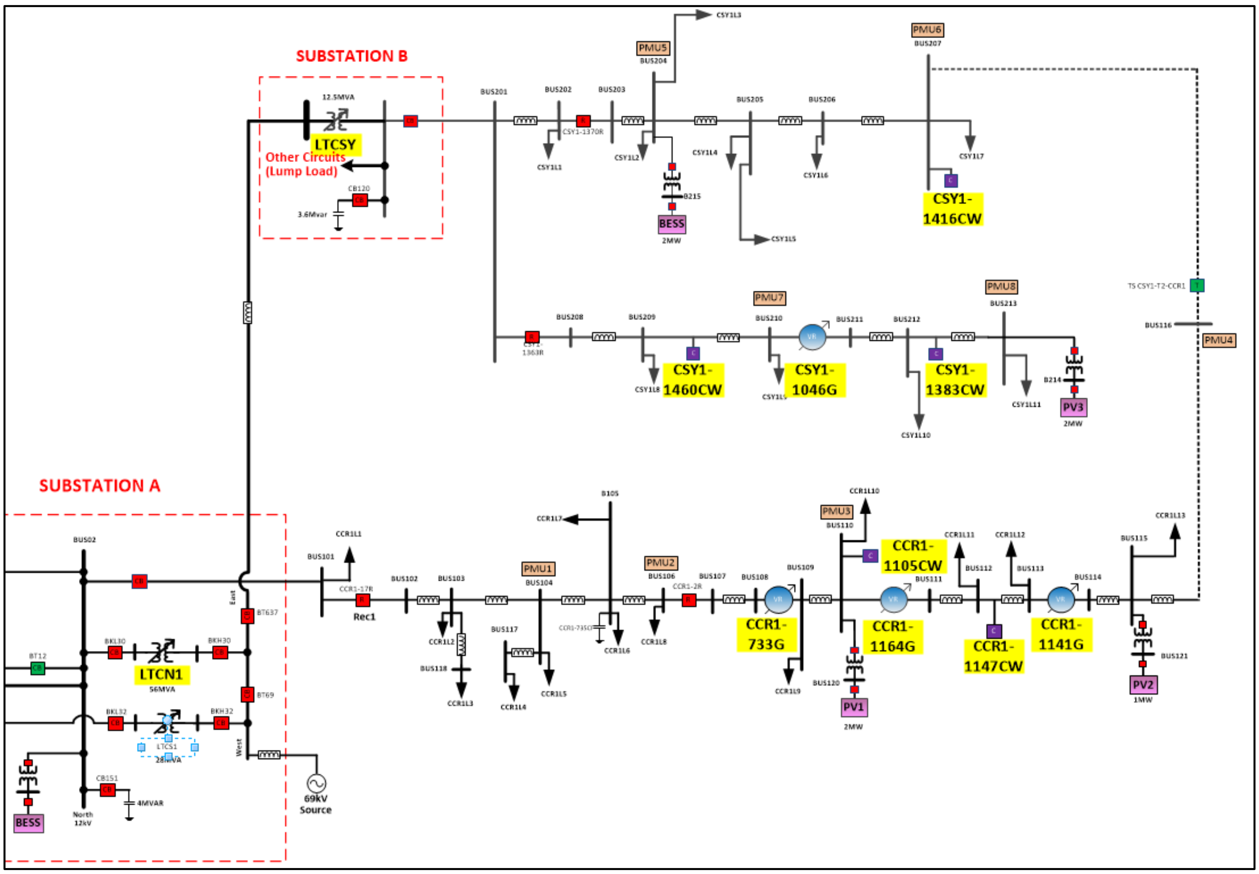
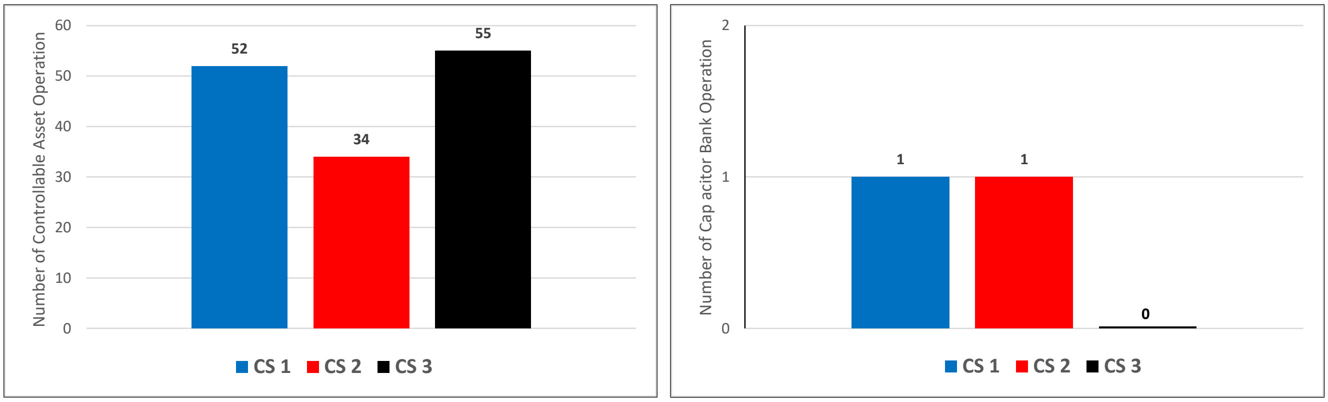


Figure 2-38. Device identifier of controllable devices.

Figure 2-39 represents an illustrative comparison between the total numbers of asset operation (and capacitor bank operation). Although there was not an improvement for the third control scenario (for the sake of optimal voltage values), the number of operation improved by about 35% for CS 2.



(a) **(b)**

Figure 2-39. Number of controllable device operations under different control scenarios: (a) total numbers of operations and (b) capacitor bank operation.

In summary, the analysis of results for ARC use case shows that, with a central ARC (CS 2 or CS 3), the system performance improved significantly. Although the results of CS 3 were not as good as CS 2, it should be borne in mind that the substation controller can offer the same functionality as the master controller if (i) it has adequate analysis capability and (ii) it can communicate with all required controllable field devices.

2.4.4.4 Trip PV 1 (high load and high PV profile)

This section provides the results of a more realistic case that can potentially occur in real life. In this case, while the system was in the steady-state condition (with high load profile[11] and high PV generation profile),[12] PV1 was tripped (*e.g.*, due to a fault) causing the system to lose approximately 1800kW of generation. The load and PV profiles were obtained based on the analysis of historical data.

Figure 2-40 shows a simplified single-line diagram of the study system with the location of PV1 highlighted. After running the system for about 30 minutes with actual load and PV profiles, PV1 was suddenly tripped. For such a contingency case, the system performance was analyzed under two control scenarios, *i.e.*, CS 1 (Case 1.13 in Table 2.16) and CS 2 (Case 1.14 in Table 2.16), and the results are presented and briefly discussed in the following subsections.

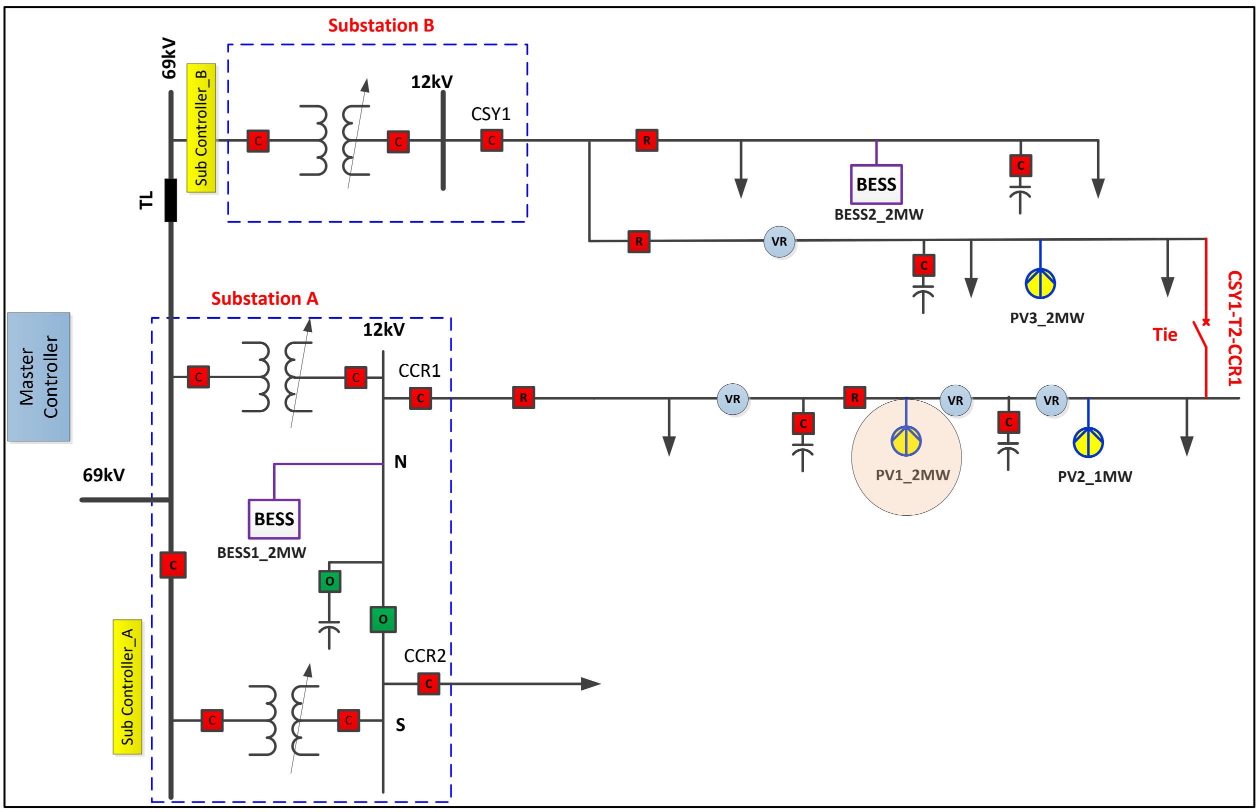


Figure 2-40. Simplified SLD of the study system

2.4.4.4.1 Voltage profile

Figure 2-41 (a) and Figure 2-41 (b) show the voltage profile of Circuit CCR1 for Cases 1.13 and 1.14, respectively. The figures clearly show that, under Control Scenario 2 (CS 2), the system reacted quickly

[11] High load profile is selected based on the analysis of historical load data, which is a summer day. Similarly, low load profile data is a winter day.

[12] High PV generation is selected based on the analysis of historical solar radiation data, which is 11am to 1pm of a sunny day. Similarly, low PV profile is 4pm to 6pm of a regular day.

to the DER trip, way before the voltage could go below the permissible threshold (see Figure 2-41 (b)). In contrast, under Control Scenario 1 (CS 1), the system voltage entered the excessive range for about 60 seconds before the first control action was taken. Further, under CS 1, the steady-state voltage of Bus 110 stayed in the moderate range.

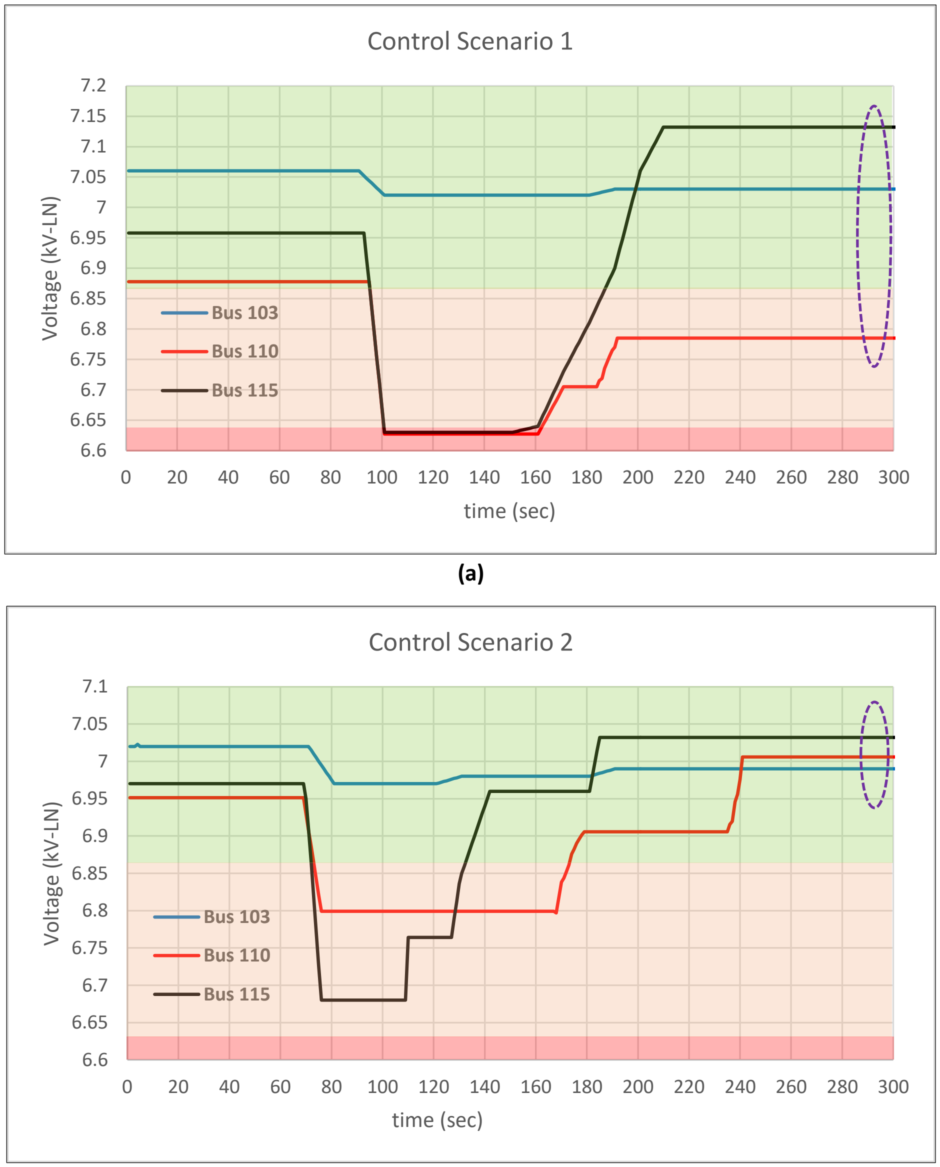


Figure 2-41. Voltage profile of circuit CCR1 for (a) Case 1.13 (CS 1) and (b) Case 1.14 (CS 2)

It is important to note that steady-state voltage values had a much flatter profile under CS 2 when compared to the same voltages values under CS 1 (see dash circled areas in Figure 2-41 (a) and Figure 2-41 (b) above). This is further illustrated in Figure 2-42, where the steady-state voltage value of some busses stayed in the moderate range (orange) under CS 1 while the same values were in the acceptable range under CS 2. This re-emphasized that ineffective/insufficient contribution of DERs in local mode caused significant voltage drop at the end of the line for CS 1 (see blue line in Figure 2-42).

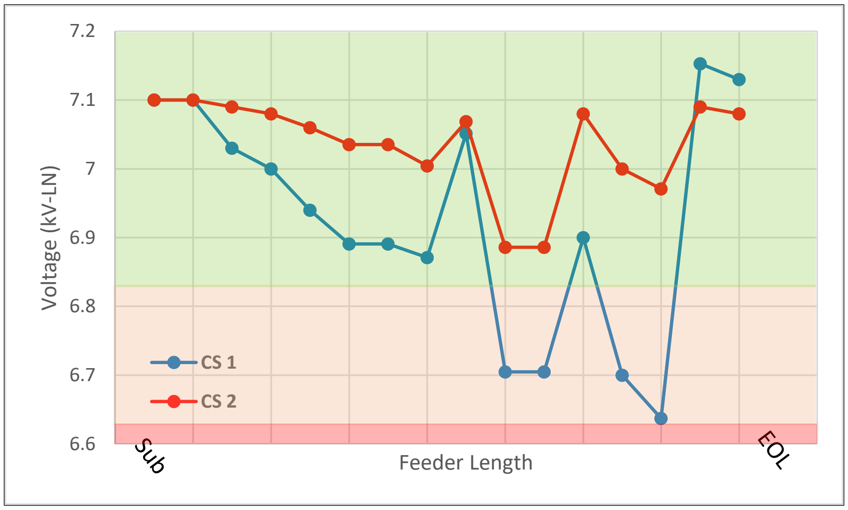


Figure 2-42. Steady-state voltage profile along Circuit CCR1 under various control scenarios

2.4.4.4.2 Power losses

Figure 2-43 shows the power loss calculated for Substation A for Case 1.13 (CS 1) and Case 1.14 (CS 2) (see Section 2.4.4.1 for power loss equation). As indicated in the figure, the power loss generally increased subsequent to the PV trip (taking place at different instants for each case); this was due to the fact that less loads were supplied locally when a DER unit (~1800kW) tripped. Figure 2-43 also shows that the amount of loss reduction was higher when the system operated under Control Scenario 2 (steady state), as compared with Control Scenario 1. In this case, the reactive power support of DERs played a role in the loss reduction for the overall substation. Since DERs have more reactive power contribution in Case 1.14 (CS 2), the power loss reduction was higher for this case (also see Section 2.4.4.4.3).

The results of these tests showed that the steady-state power losses under CS 1 and CS 2 were 1120.4kW (3.27%) and 1022.5kW (2.98%), respectively. Therefore, there was 0.29% improvement in power loss when the system operated under Control Scenario 2.

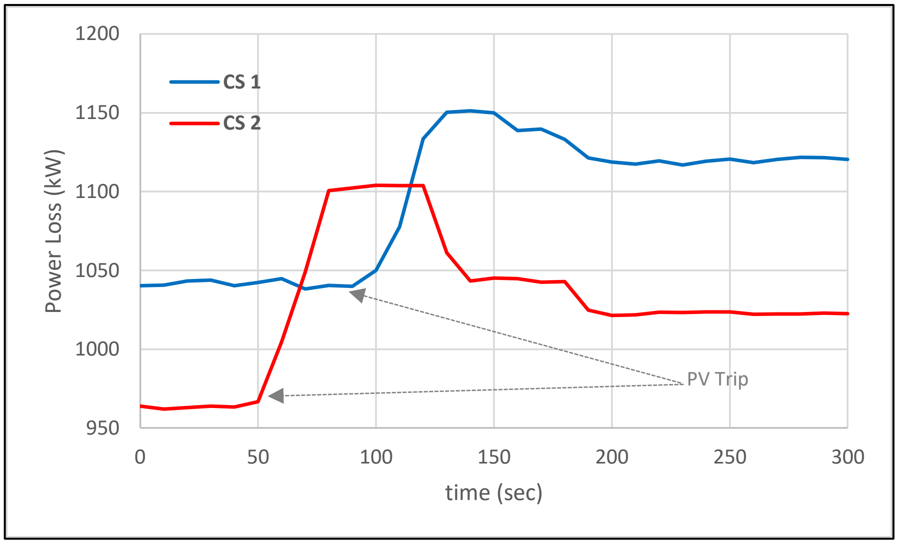


Figure 2-43. Power losses for Substation A substation (cases 1.13 and 1.14)

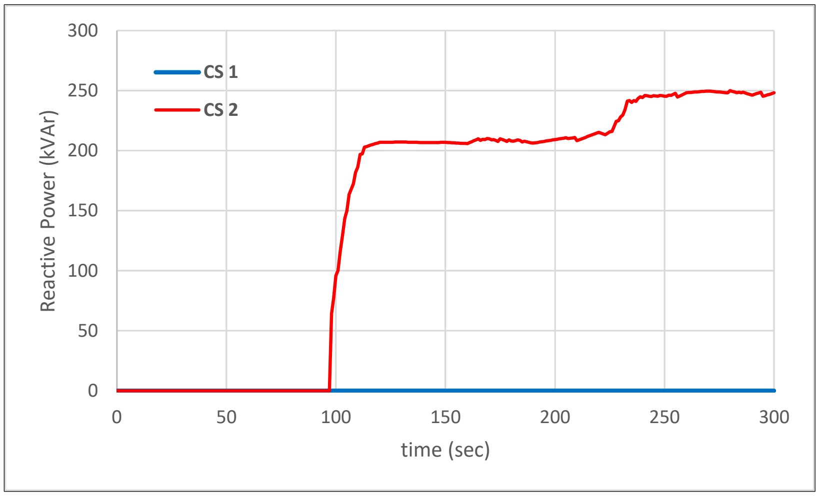
2.4.4.4.3 DER involvement/contribution

The reactive power contributions of all DERs in Circuit CCR1 are plotted in Figure 2-44(a), (b), and (c) for both control scenarios. It can be observed in these figures that all DERs injected more reactive power to the circuit under Control Scenarios 2 (CS 2) in order to regulate feeder voltage or adjust the circuit power factor. For example, Figure 2-44(a) shows that the battery energy storage system at the substation (BESS 1 in Figure 2-13) did not inject any reactive power to the grid under CS 1. However, with the ARC algorithm activated (CS 2), the reactive power contribution of BESS 1 was adjusted by the ARC engine (master controller in this case) such that it supported the grid by injecting about 250 kvar reactive power in the steady-state condition.

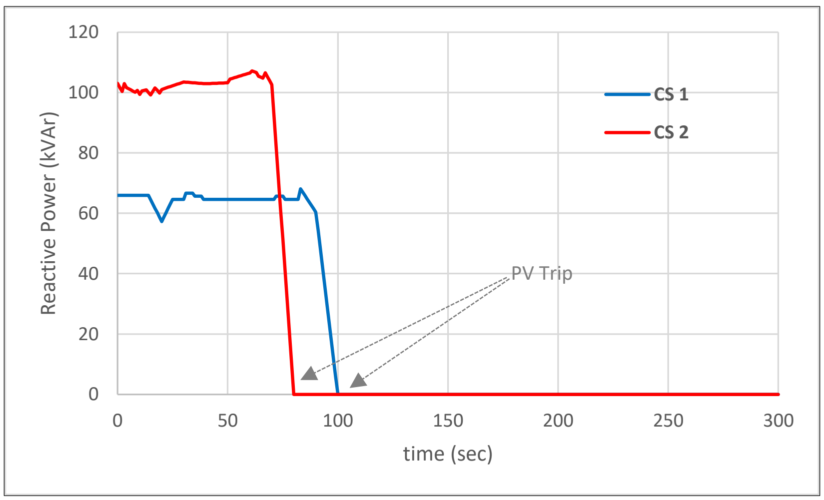
A comparison of total reactive power injection by DERs on Circuit CCR1 showed that they injected around 480 kvar more reactive power to the circuit under CS 2 (relative to CS 1). It should, however, be acknowledged that part of this var contribution by DERs was to adjust power factor at the circuit/feeder level.

2.4.4.4.4 Power factor

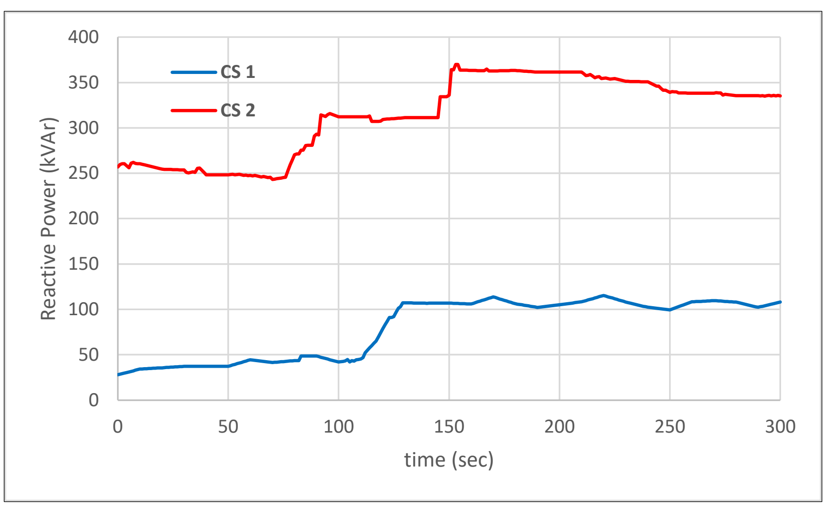
Figure 2-45 shows the reactive power flowing through Circuit Breaker CCR1 (CB CCR1 Figure 2-13) before and after the PV trip, for a 5-minute time frame. As indicated in this figure, under the second control scenario with ARC in place (CS 2), the reactive power flow at the feeder level was close to zero. This is because one of the objectives of the ARC algorithm is to improve overall system power factor through the regulation of reactive power. In other words, the master controller tried to maintain power factor of the circuit at unity. This is evident in Figure 2-45 where the circuit var value was around zero under CS 2 (green band in Figure 2-45). It should also be pointed out that the accurate adjustment of power factor was achieved through the effective control of DERs.



(a)



(b)



(c)

Figure 2-44. Reactive power contribution of DERS (in Substation A) for cases 1.13 (CS 1) and 1.14 (CS 2): (a) Substation BESS reactive power, (b) PV1 reactive power, and (c) PV2 reactive power

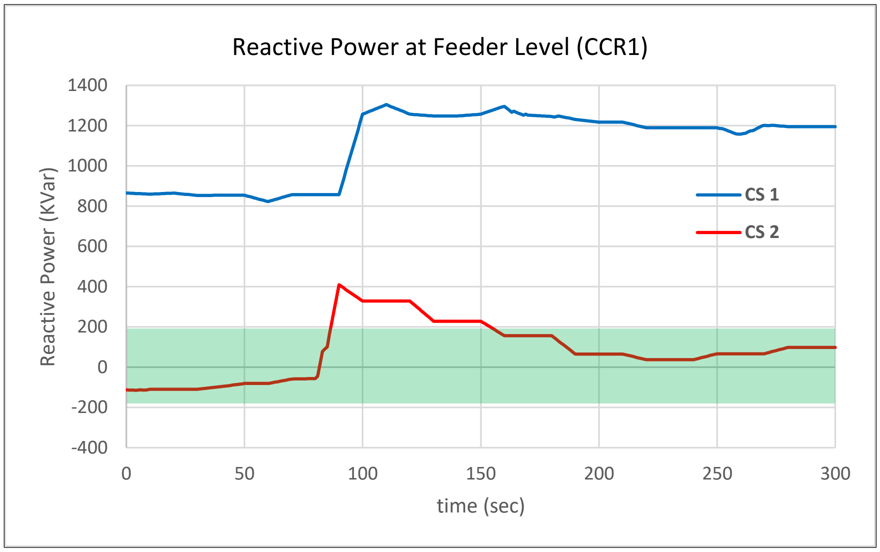
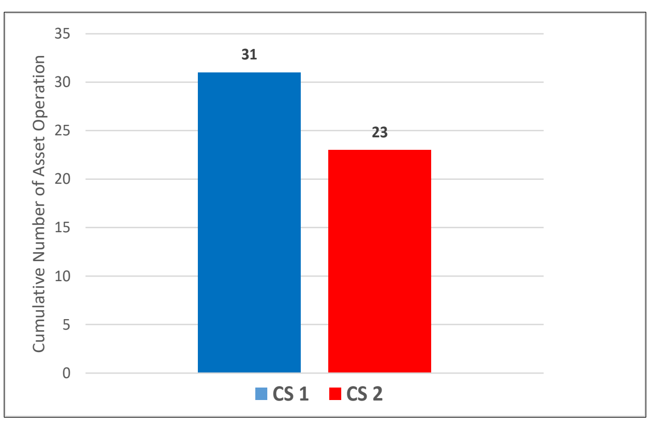


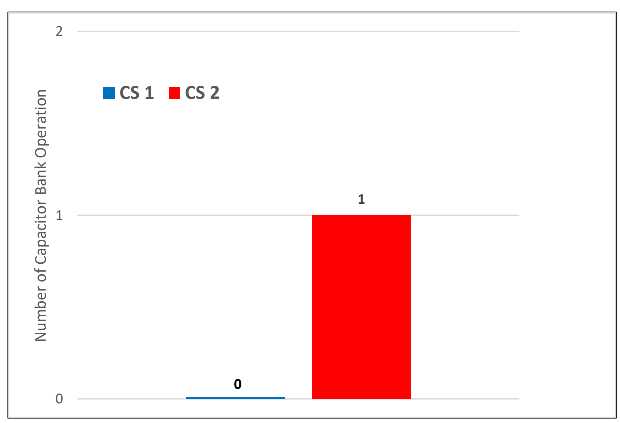
Figure 2-45. Reactive power at the feeder level for cases 1.13 and 1.14 (PV trip)

2.4.4.4.5 Asset operation

Figure 2-46(a) and Figure 2-46(b) respectively show the cumulative numbers of device operation and number of capacitor bank operation for Case 1.13 and Case 1.14. It is evident from the figures that the cumulative number of operation of controllable assets was reduced by about 26% with the master controller in charge (i.e., CS 2). In addition to the enhanced DER contribution, switching on the capacitor bank CSY1-1383CW avoided additional operation of other controllable assets. It should be noted that, as opposed to local mode control that had a minimum start time for capacitor bank energization, the master controller could quickly send the close/trip commands to the capacitor bank (in remote mode), knowing its operation history.



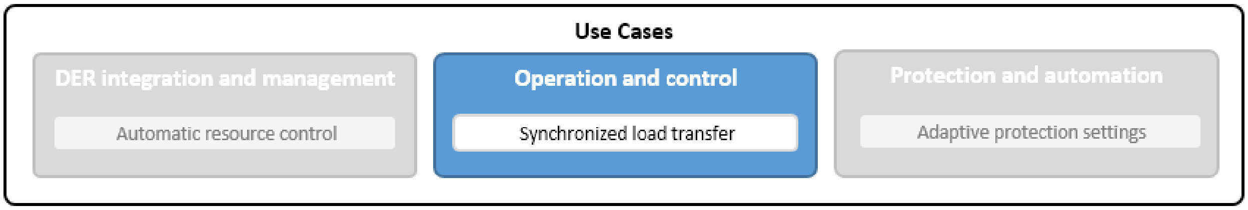
(a)



(b)

Figure 2-46. Number of controllable device operations for case 1.13 (CS 1) and case 1.14 (CS 2): (a) cumulative numbers of operations and (b) capacitor bank operation.

2.4.5 Use case 2: Synchronized Load Transfer



The Synchronized Load Transfer (SLT) application utilized four control blocks in various levels to optimize circuit reconfiguration:

- Feeder Injection Test (FIT) tool
- Near-Real-Time Power Flow (NRTPF) model
- Real-time SCADA measurements
- Synchronization check function

The Feeder Injection Test (FIT) tool determined whether there were circuit performance violation(s) that should be corrected by Synchronized Load Transfer (SLT). In the event that violations were detected, FIT used real-time field/SCADA data, load/generation forecast results, and the Near-Real-Time Power Flow Model (NRTPF) to determine if the circuit violation needed to be addressed by the load transfer (rather than resource control). Both FIT and NRTPF blocks were located at the control-center level in the master controller.

For all test cases, the SLT function identified the switches to operate for the desired system reconfiguration. Since the load transfer was executed while the system was energized (without any power interruption), a synchronization check had to be performed. The voltages on both sides of the tie switch (magnitude, phase angle, and frequency) were checked to ensure they were synchronized. If this condition was not met, Load Tap Changer (LTC) settings, capacitor bank controller settings, and/or DER outputs were controlled to achieve synchronization.[13] Once voltage synchronization was established by the SLT, the tie switch was closed, followed by opening of the upstream isolating switch(s) to complete the transfer. The synchronization check was performed through the collaboration of field and substation devices.

The SLT application performed the following functions:

- Utilized the results of the FIT tool or an operator request to trigger further action
- Acquired information about all tie and isolating switches in the distribution system, including their current status
- Determined if the load transfer could improve system condition (power quality, loading, etc.) using FIT and NRTPF models
- Identified the tie and isolating switches that needed to be operated for optimal system reconfiguration
- Checked synchronization between two parts of the distribution network (voltages on both sides of the tie switch)

[13] It should be pointed out that the frequency and phase angle of the voltages (on both sides of the tie switch) were in the acceptable synchronization range for distribution systems.

- If the voltage phasors were not synchronized, it would change LTC settings, capacitor bank controller settings, and/or DER output powers to synchronize the voltages (magnitude, phase angle, and frequency)
- Sent trip/open commands to tie/isolating switch(s) via SCADA
- Received synchronization confirmation signal (and closure confirmation) from the tie switch
- Triggered alarms if:
  - Load transfer couldn't resolve the circuit violation
  - Load transfer couldn't be accomplished due to the current state of switching devices
  - Communication network failed
  - Communication with the target switch failed
  - The target switch failed to operate
- Sent SLT completion confirmation to higher control level *i.e.*, Distributed Energy Resource Management System (DERMS) or Distribution Management System (DMS) or SCADA.

Figure 2-47 provides the sequence diagram of the SLT applications, showing the interaction between the ARC and SLT applications. As illustrated, once the application determined the ARC was unable to resolve the circuit violtion (e.g. excessive reserve power flow), the SLT application would check the possibility of the load transfer without system interruption (green box in Figure 2-47).

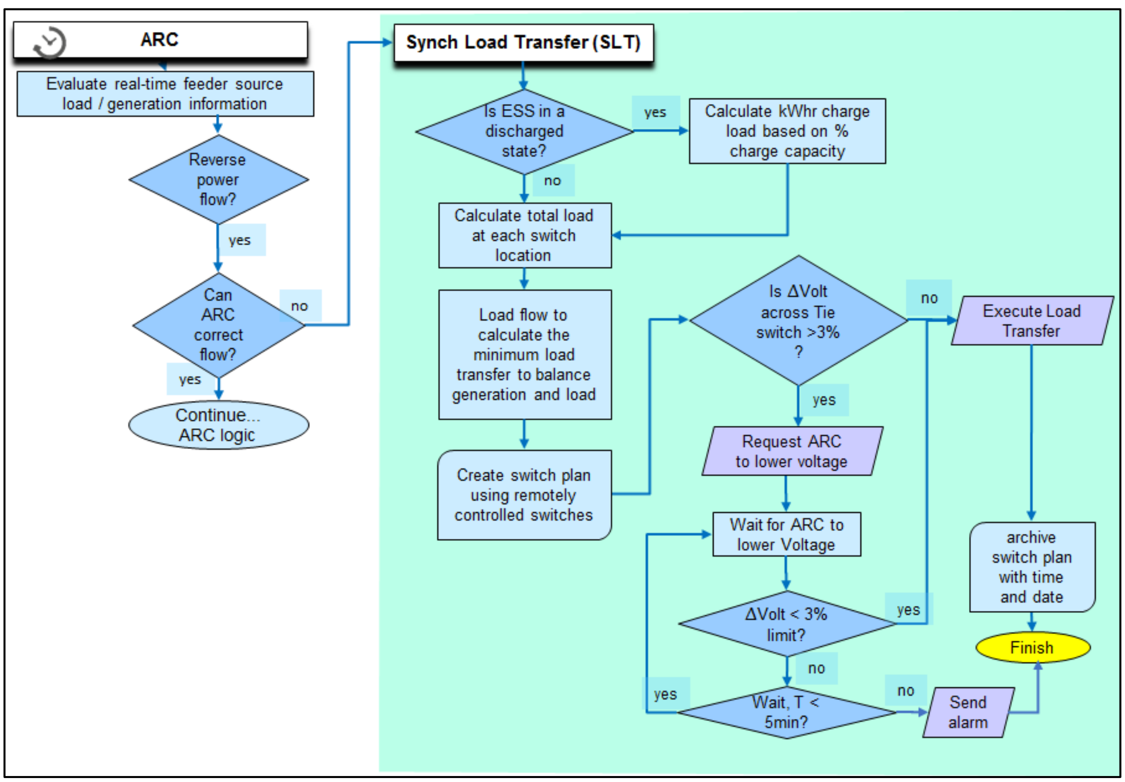


Figure 2-47. Synchronized Load Transfer

2.4.5.1 Performance criteria

The main objectives of the SLT use case was to prevent unintentional excessive reverse power flow within distribution circuits or at the substation level. The SLT function should transfer some part of a circuit to another one in order to avoid reverse power flow in the circuit. It should be noted that the SLT use case would only function if the ARC was not capable of optimally addressing the situation. Therefore, if the reverse power flow was reduced as a results of the SLT application, it was considered as successful test. The successful completion of the function also required the transfer be done in a synchronized manner.

2.4.5.2 Test results

The purpose of this test category was to verify that the master controller and substation controllers could collectively perform load transfer between two circuits (from two different substations) when such a need arose. The main criterion for performing a load transfer was excessive reverse power flow measured along the feeder, *e.g.*, when the DER penetration/injection was high. Under such a scenario, it was very unlikely that the ARC function would be able to address circuit violation without any curtailment. As a result, the possibility of SLT was evaluated through proper coordination between ARC and SLT engines.

It is emphasized that the salient feature of the SLT is that the transfer is executed in a synchronized manner, meaning it will be performed only if the voltage phasors on both sides of the tie switch are cophasal and of almost equal magnitude (the instantaneous voltage across the tie switch should be adequately small). If the synch-check signal is not received from the tie switch relay, the transfer cannot be accomplished. In such a case, the SLT function will adjust the settings of controllable assets to bring the voltage magnitude across the tie to an acceptable range. As soon as this happens, the tie switch relay will issue the synch-check signal such that the SLT can be initiated and completed.

Several test cases were considered in this category to ensure proper operation of the SLT application (both security and dependability). Figure 2-48 lists major test cases conducted for the evaluation of the SLT application. Similar to the ARC use case, the test cases were designed to examine system performance under three control scenarios described in Section 2.4.4.2 (CS 1, CS2, and CS 3); the results of selected test cases are presented and discussed in this section.

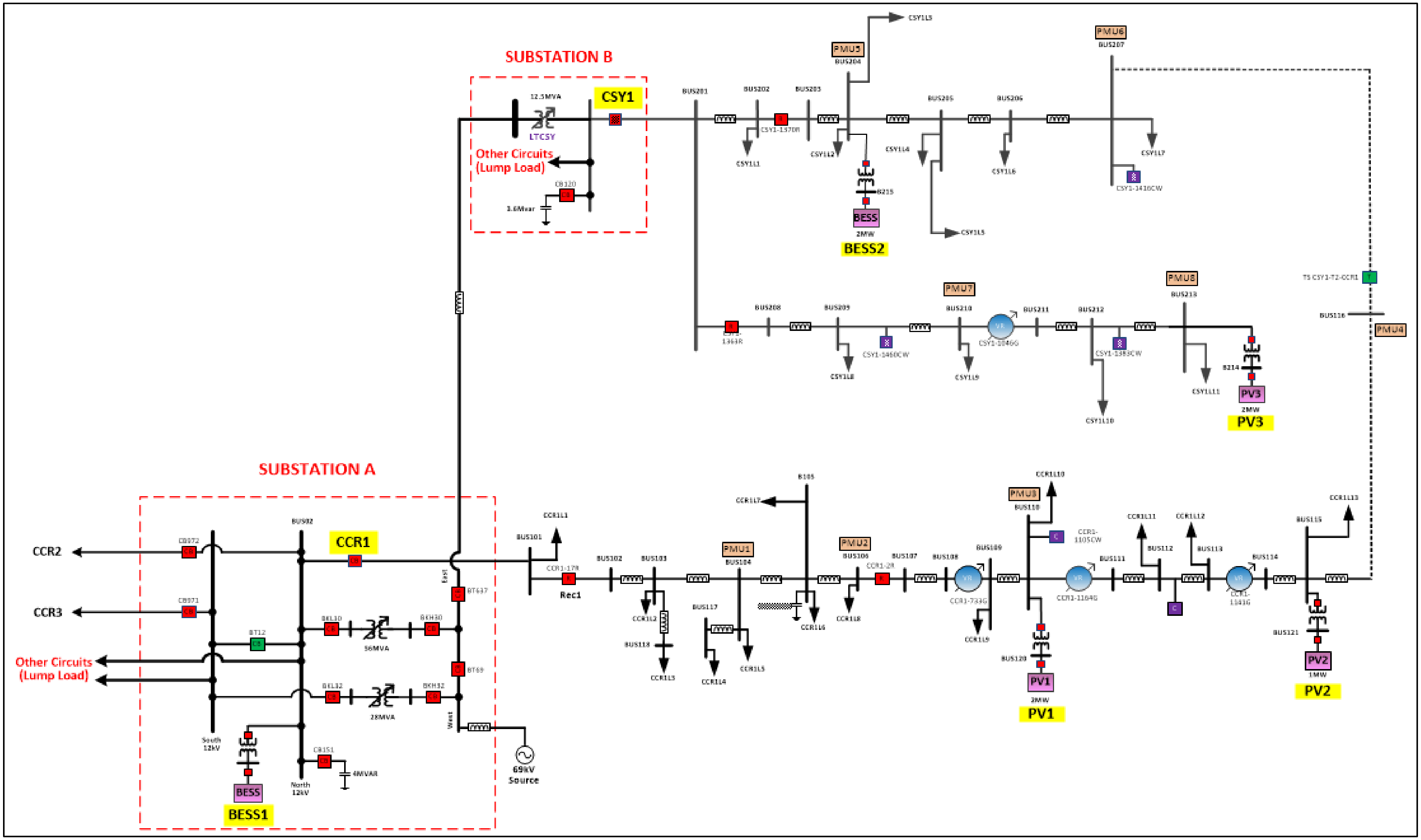


Figure 2-48. Identification of devices referenced in use case 2 test cases

Table 2.20. SLT test cases

Case#	Test Condition	Description	Remark
2.1	CCR1: PLoad=2.1MW, PPV1=2MW, PPV2=1MW, PBESS1=0 CSY1: PLoad =2.3MW, PPV3=0 (PV was not available), PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix), PV3 tripped	Baseline System 2 (all controllable devices were in Local/Auto mode)
2.2	CCR1: PLoad =2.1MW, PPV1=2MW, PPV2=1MW, PBESS1=0 CSY1: PLoad =2.3MW , PPV3=0 (PV was not available), PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix), PV3 tripped	Master controller was responsible to take actions through SLT/IVVC algorithm.
2.3	CCR1: Pload=2.1MW, PPV1=2MW, PPV2=1MW, BESSOutput=0 CSY1: Pload=2.3MW, PPV3=0 (PV was not available), PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix), PV3 tripped	Sub controller was responsible to take actions through permission of communication loss (prior to event)
2.4	CCR1: PLoad =2.1MW, PPV1=1MW, PPV2=0.5MW, PBESS1=0 CSY1: PLoad =2.3MW, PPV3=1.0MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
2.5	CCR1: PLoad=2.1MW, PPV1=1MW, PPV2=0.5MW, PBESS1=0 CSY1: PLoad=2.3MW, PPV3=1.0MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Master controller was responsible to take actions through SLT/IVVC algorithm.
2.6	CCR1: Pload=2.1MW, PPV1=1MW, PPV2=0.5MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Sub controller was responsible to take actions through permission of communication loss (prior to event)
2.7	CCR1: PLoad=3.6MW, PPV1=1.6MW, PPV2=0.8MW, PBESS1=0 CSY1: PLoad=1.2MW, PPV3=1.4MW, PBESS2=0MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
2.8	CCR1: PLoad=3.6MW, PPV1=1.6MW, PPV2=0.8MW, PBESS1=0 CSY1: PLoad=1.2MW, PPV3=1.4MW, PBESS2=0MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Master controller was responsible to take actions through SLT/IVVC algorithm.
2.9	CCR1: Pload=2.1MW, PPV1=2MW, PPV2=1MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1.4, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Sub controller was responsible to take actions through permission of communication loss (prior to event)

For scenarios where the system is lightly loaded and the PV generation is high (e.g., test cases 2.1, 2.2, and 2.3 in Table 2.20), it is very likely that power flows through some of the protective devices along the circuit become negative. The reverse power flow can significantly impact the operation of protection and control equipment, which is not desirable. For example, when the solar radiation is suddenly increased in a light load condition (cases 2.1, 2.2, and 2.3), the direction of the active power flowing through devices on circuit CCR1 changes. Figure 2-49 shows the active power flow through two reclosers before and after the solar radiation increase. The figure indicates that the increase in the solar radiation (from 10% to 80%) could cause significant reverse power flow through the two reclosers.

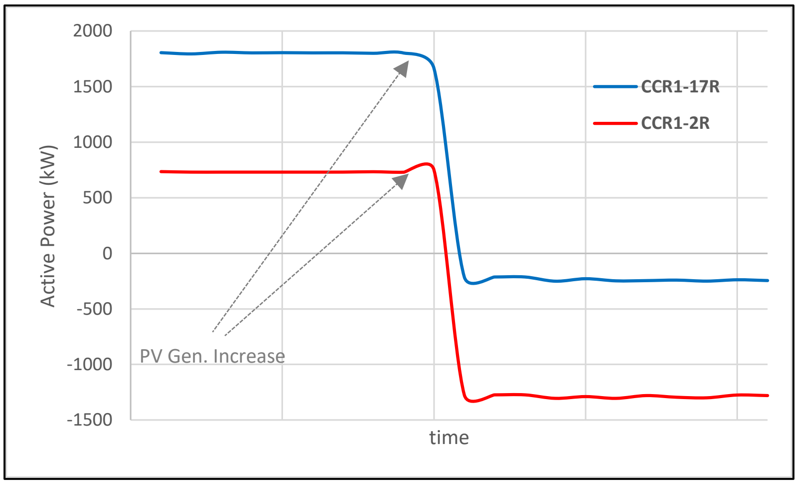


Figure 2-49. Active power flow through CCR1-2R and CCR1-17R

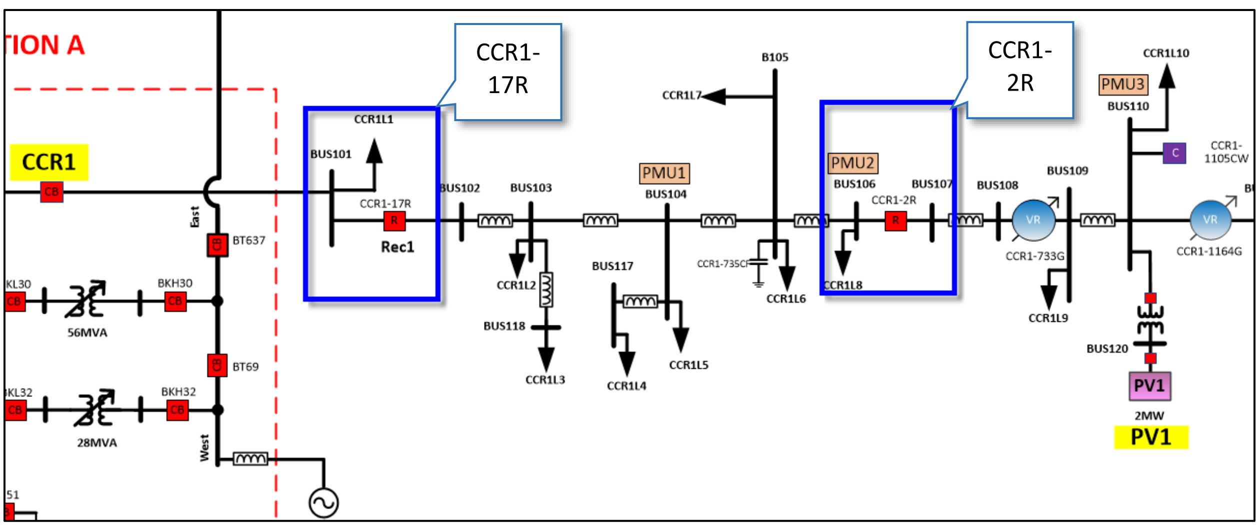


Figure 2-50. Location of CCR1-2R and CCR1-17R on SLD

Under control scenario 1 (*i.e.*, when all individual devices are in Local mode), it would be very difficult, if not impossible, to effectively manage reverse power flow while maximizing the power generation from renewable energy resources. Figure 2-51 shows the voltage profile of circuit CCR1 for control scenario 1 (CS 1), with no PV curtailment. As shown in this figure, the steady-state values of bus voltages did not settle in the permissible range. In other words, without any power curtailment, both reverse power issue and overvoltage issue could not be successfully resolved for low-load, high-generation conditions. The power of the tie switch and reclosers CCR1-2R and CCR1-17R during the entire test is plotted in Figure 2-53. It can be observed that the tie switch remains open during the test.

On the other hand, under control scenario 2 (*i.e.*, when ARC/SLT function is run in the master controller), the reverse power flow along the circuit was detected by the master controller. Since the ARC could not fully resolve the circuit violations without power curtailment, the possibility of the synchronized load transfer was evaluated by the SLT function. Once the SLT engine confirmed the load transfer could be executed, the close command was issued to the tie switch. Once the voltages on both sides of the tie switch were synchronized (*i.e.*, the synch-check command was received from the tie switch relay), the close command was applied, followed by opening the upstream isolating switch.

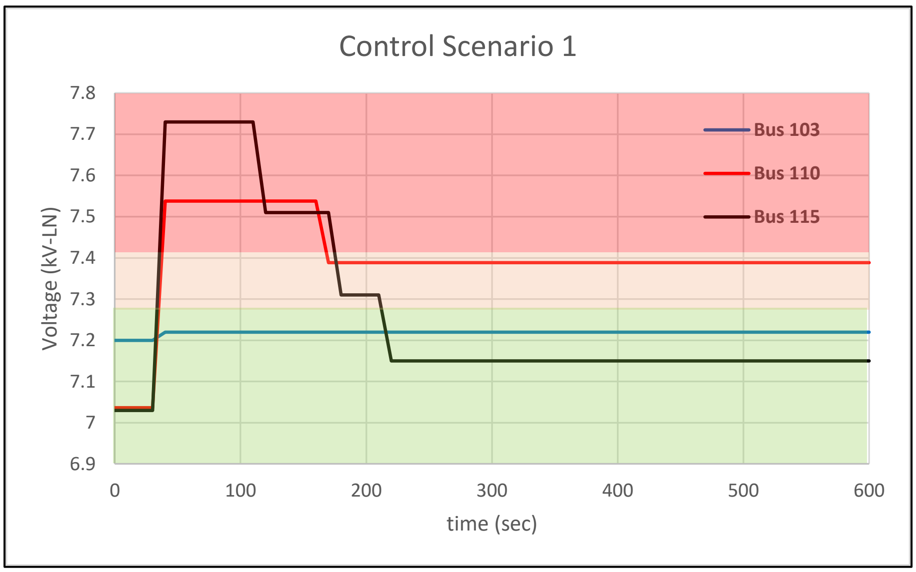


Figure 2-51. Voltage profile of circuit CCR1 for case 2.1 (CS 1) without power curtailment

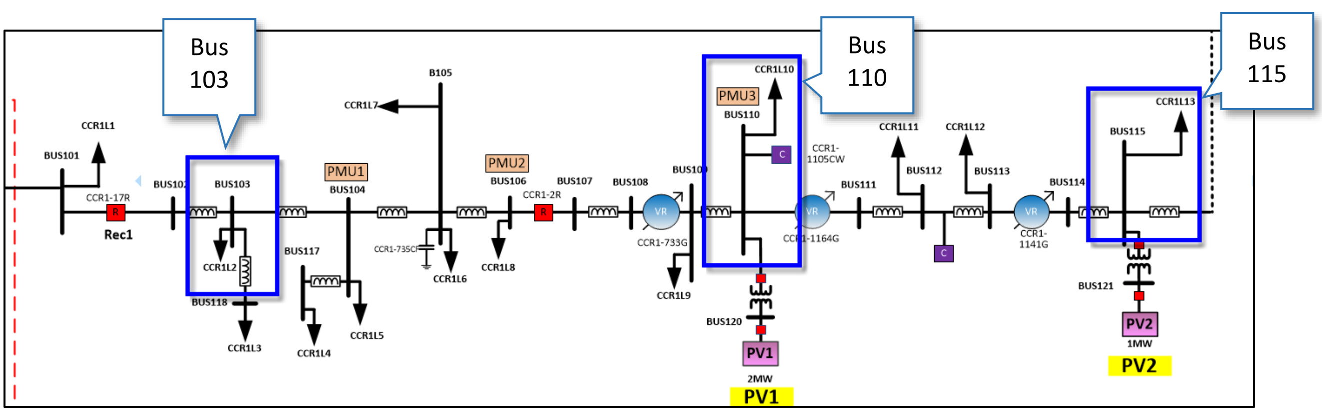


Figure 2-52. Location of Bus 103, 11, and 115 on circuit CCR1 on the SLD

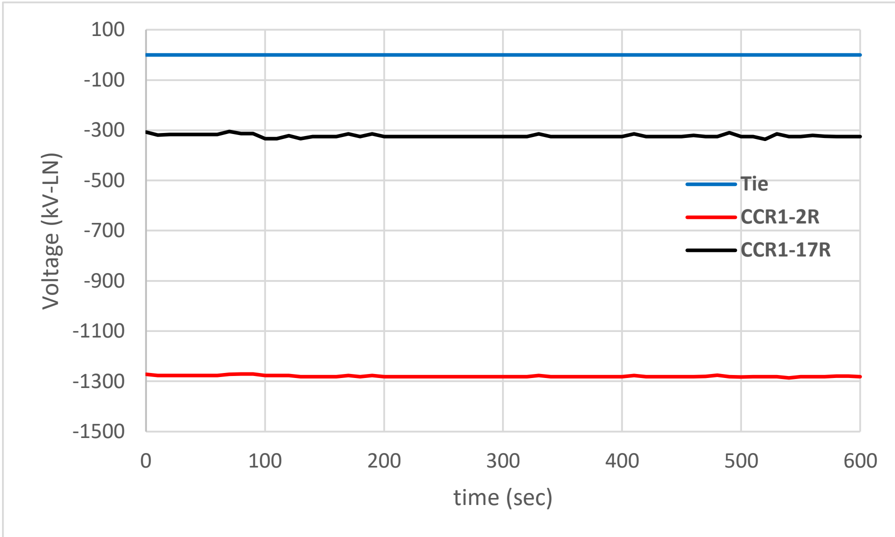


Figure 2-53. Power flow through tie switch and reclosers CCR1-2R and CCR1-17R under CS 1 (Case 2.1)

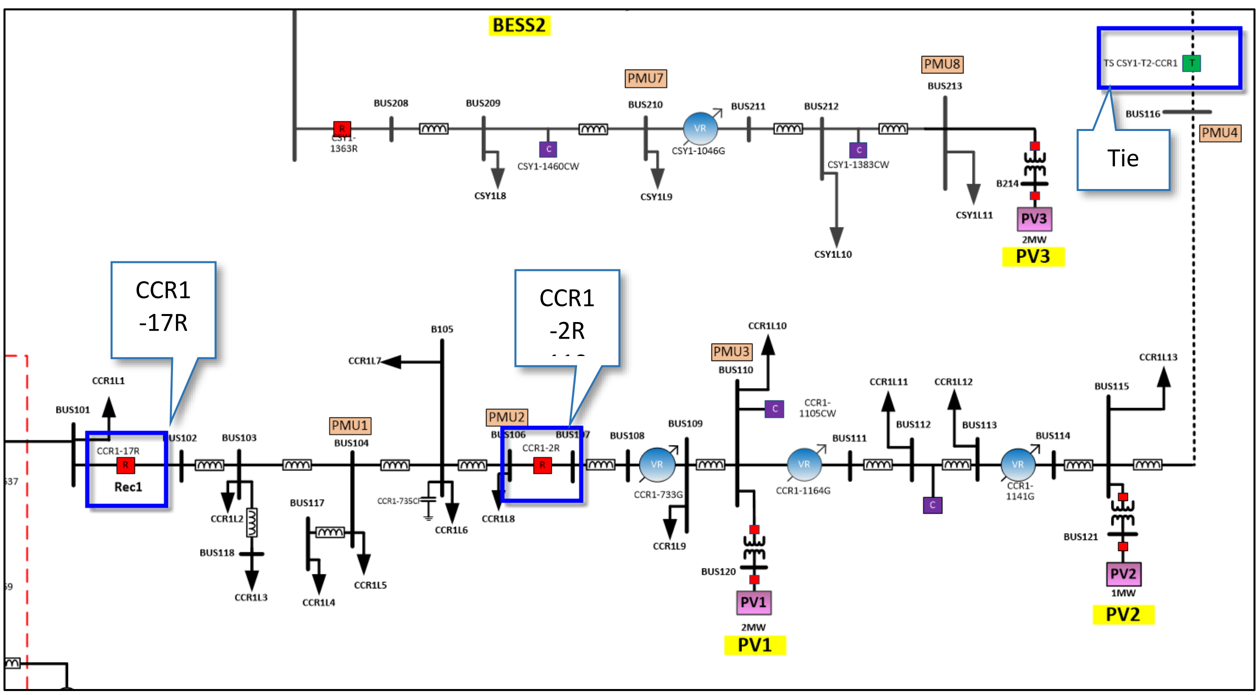


Figure 2-54 shows the voltage profile of circuit CCR1 for case 2.2 (control scenario 2). The instant at which the SLT was performed is also illustrated in the figure. As can be observed in Figure 2-54, the steady-state values of bus voltages stayed in the permissible range after the load transfer. Further, the load transfer resolved the reverse power flow issue in circuit CCR1. The power flow through the tie switch, recloser CCR1-2R and recloser CCR1-17R are plotted in Figure 2-55 before and after the SLT. It is evident that, subsequent to the SLT, the active power flowing through both reclosers became zero/positive.

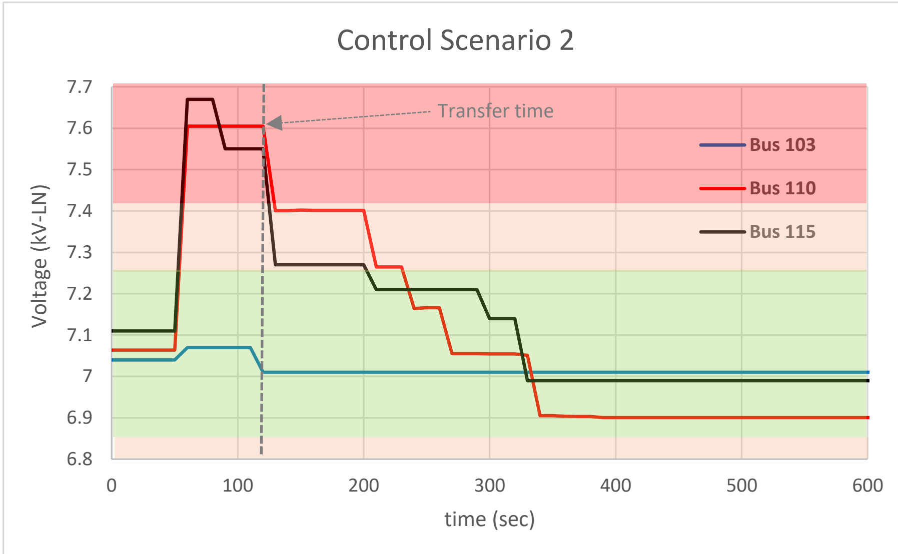


Figure 2-54. Voltage profile of circuit CCR1 for case 2.2 (CS 2)

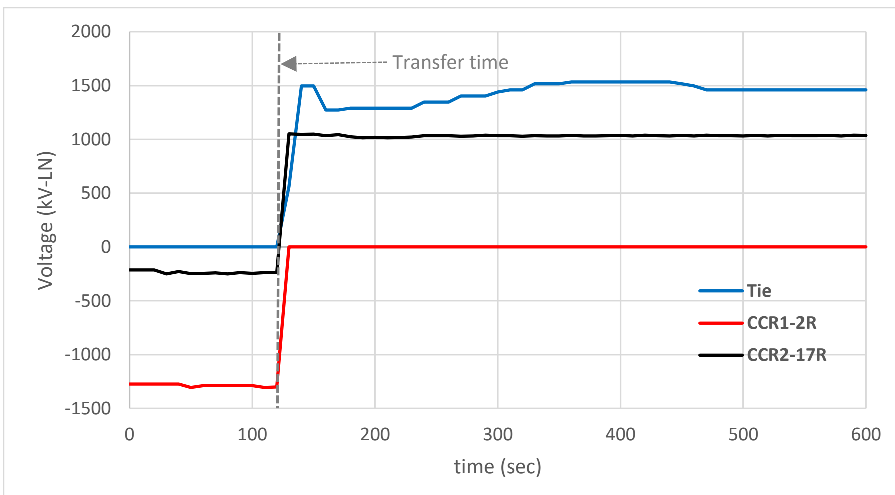


Figure 2-55. Power flow through tie switch and reclosers CCR1-2R and CCR1-17R under CS 2 (Case 2.2)

Figure 2-56 shows the voltage profile of circuit CCR1 for case 2.3 (control scenario 3). The instant at which the SLT was performed is also indicated in this figure. Similar to case 2.2, the steady-state values of bus voltages stayed in the permissible range after the load transfer (see Figure 2-56). However, compared to Case 2.2, the accumulative number of asset operation increased under CS 3 as the substation controller did not has the same observability/access as the master controller.

In addition to the voltage profile, the load transfer resolved the reverse power flow issue in circuit CCR1. Figure 2-57 shows the power flow through the tie switch, recloser CCR1-2R, and recloser CCR1-17R under control scenario 3, before and after the SLT. As shown in the figure, subsequent to the SLT, the active power flowing through both reclosers became zero/positive.

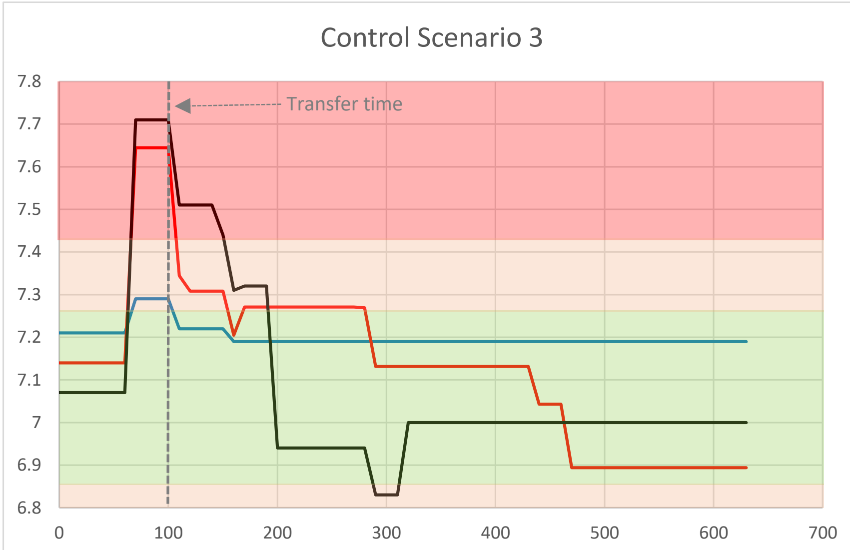


Figure 2-56. Voltage profile of circuit CCR1 for case 2.3 (CS 3)

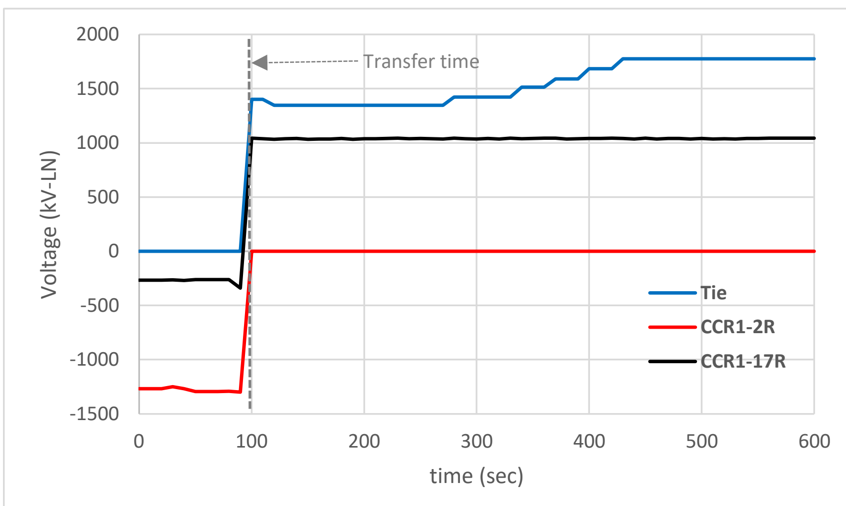
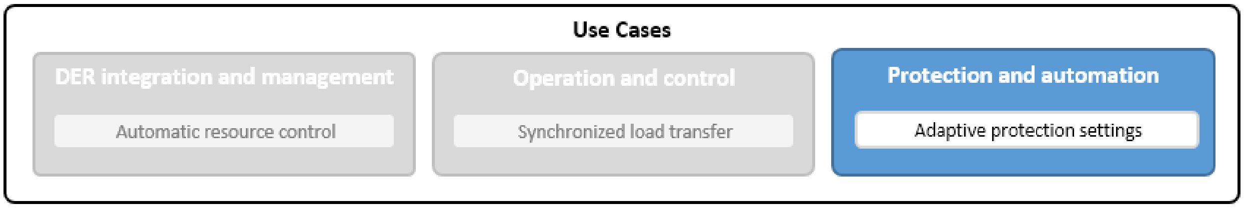


Figure 2-57. Power flow through tie switch and reclosers CCR1-2R and CCR1-17R under CS 3 (case 2.3)

The test cases listed in Table 2.20 were executed, and the SLT was performed successfully when it was necessary. The results show that the SLT could help with reverse power flow management in distribution circuits with high penetration of DERs. Further modifications are possible to ensure a smooth transition, by making corrective actions prior to the SLT initiation (beyond the scope of this project).

2.4.6 Use case 3: Automatic protection setting changes



The APS was tasked with determining if the forecasted or real-time distribution system condition/topology required changing protection setting groups. It would then determine the correct protection setting groups based on the prevailing system condition/configuration. The APS would finally send commands to appropriate protective devices or IEDs in order to change protection settings.

The APS provided the following functionalities:

- Dynamically received state of switching devices for any changes in system;
- Determined the global topology of the system based on the received data;
- Determined whether or not the protection setting groups should change for the new system condition/configuration;
- Identified appropriate protection setting groups for the new system condition/configuration (from the setting-topology database);
- As required, sent protection setting changes to the corresponding protective devices;
- Received confirmation on active protection settings from protective devices or IEDs; and
- Defaulted to safe condition in the event of failures.

In the event of a circuit reconfiguration, the APS would immediately evaluate the new configuration, determine the proper setting group, and request the changes if necessary. The APS processing occurred centrally which required visibility and access to protective devices, IEDs, and switching devices. Topology algorithm in the APS processor dynamically determined the electric configuration of the distribution system. Every time a change of state of a switching device was indicated, the topology algorithm was run to determine if there was a need for protection setting change. Thus, the APS system required the current state of switching devices and protection IEDs to detect changes in system configuration and to trigger the protection setting changes, if it was necessary.

Once the need for a protection setting change was established, commands would be sent to specific protective devices or IEDs to change their setting group. When a protective device or IED received the command to change its setting, it was required to send back confirmation indicating that a change had occurred as well as the active protection setting group in place. The APS would trigger alarms or flag an issue if:

- Security and/or dependability of the protection system (fault detection, isolation, and coordination) was fully/partially violated due to the system changes;
- Communication network had failed;
- Communication with a specific protective device(s) or IED(s) had failed; and
- Target settings could not be applied.

Entities requesting the APS service included the APS Processor (automatically) or the System Operator (manually). It should be noted that, in the test system architecture, the control was distributed within the system, and the Substation Controller was responsible for executing some control functions. Therefore, in the case of a single processor failure (e.g., communication failure to central controller) the lower-level distributed controllers could manage the execution of some control functions to ensure fail-safe functions.

2.4.6.1 Performance criteria

Subsequent to a system reconfiguration (*e.g.*, due to a load transfer), the APS function was tasked with changing the protection setting group of specified protective devices if it was essential to do so. The APS function was continuously monitoring the status of the distribution system and would change the setting group based on the defined lookup table. The defined topologies/configurations for the system under study are shown in Table 2.21. For each topology, a set of protection setting group was also defined for specified protective assets as shown in Table 2.22. As soon as one of the system topologies was sensed by the logic, proper protection setting group were communicated to the corresponding protective device.

Table 2.21. Defined topologies for the test system

Configuration #	Configuration name	Switch/breaker status				
		TSCSY1-T2-CCR1	TSCCR1-T1-972	CCR1-17R	CCR1-2R	CSY1-1370R
1	Normal	Open	Open	Closed	Closed	Closed
2	Transfer 1	Closed	Open	Closed	Open	Closed
3	Transfer 2	Closed	Open	Closed	Closed	Open
4	Transfer 3	Open	Closed	Open	Closed	Closed
5	Transfer 4	Closed	Closed	Open	Open	Closed

Table 2.22. Defined protection setting group for each system topology

Protection setting group							
CB CCR1	CB CSY1	TS CSY1-T2-CCR1	TS CCR1-T1-972	CCR1-17R	CCR1-2R	CSY1-1370R	CB972
1	1	as is (1)	as is (1)	1	1	1	1
2	2	1	as is (1)	2	as is (1)	2	1
3	3	2	as is (1)	3	2	as is (1)	1
1	1	as is (1)	1	as is (1)	1	1	2
1	2	1	2	as is (1)	as is (1)	2	3

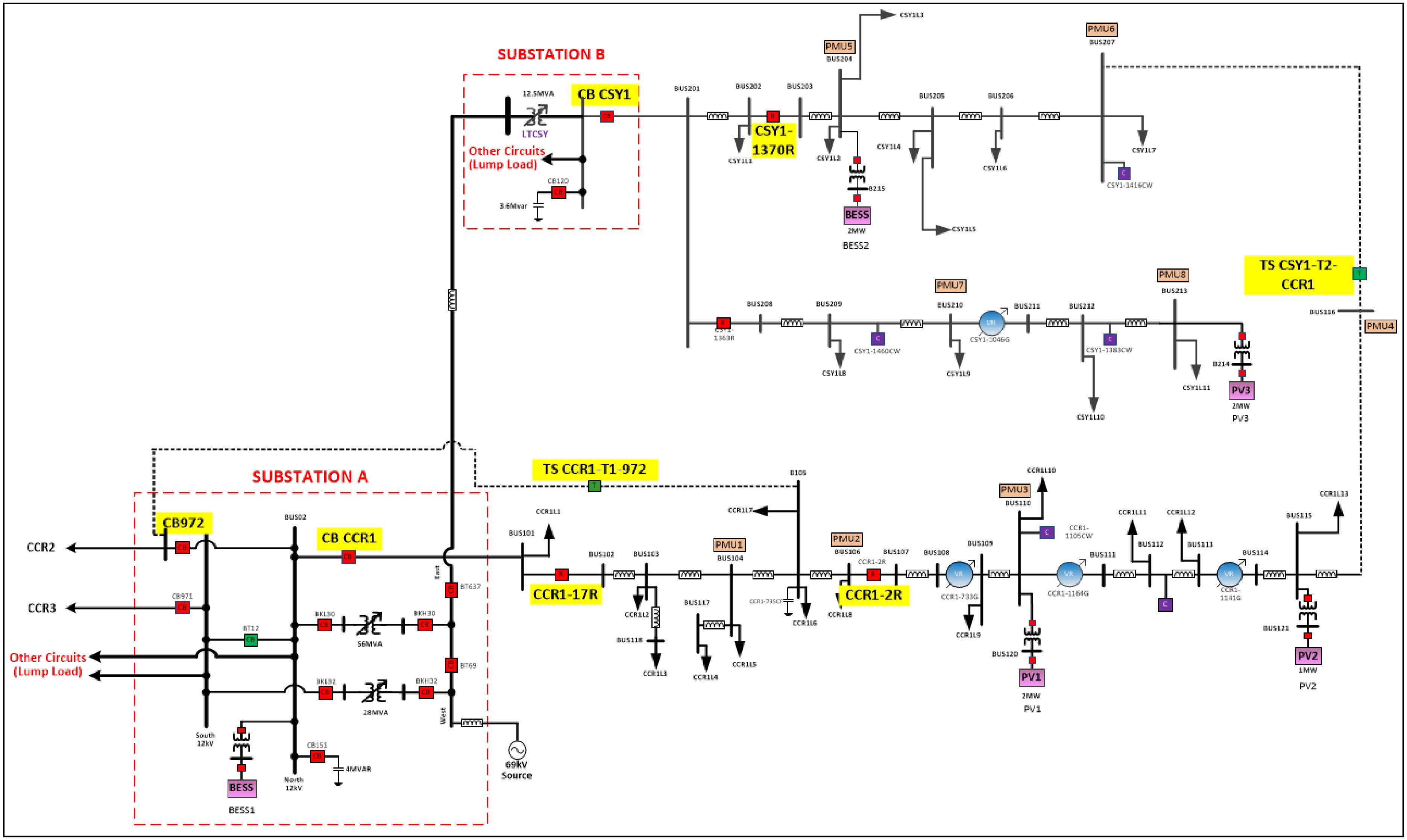
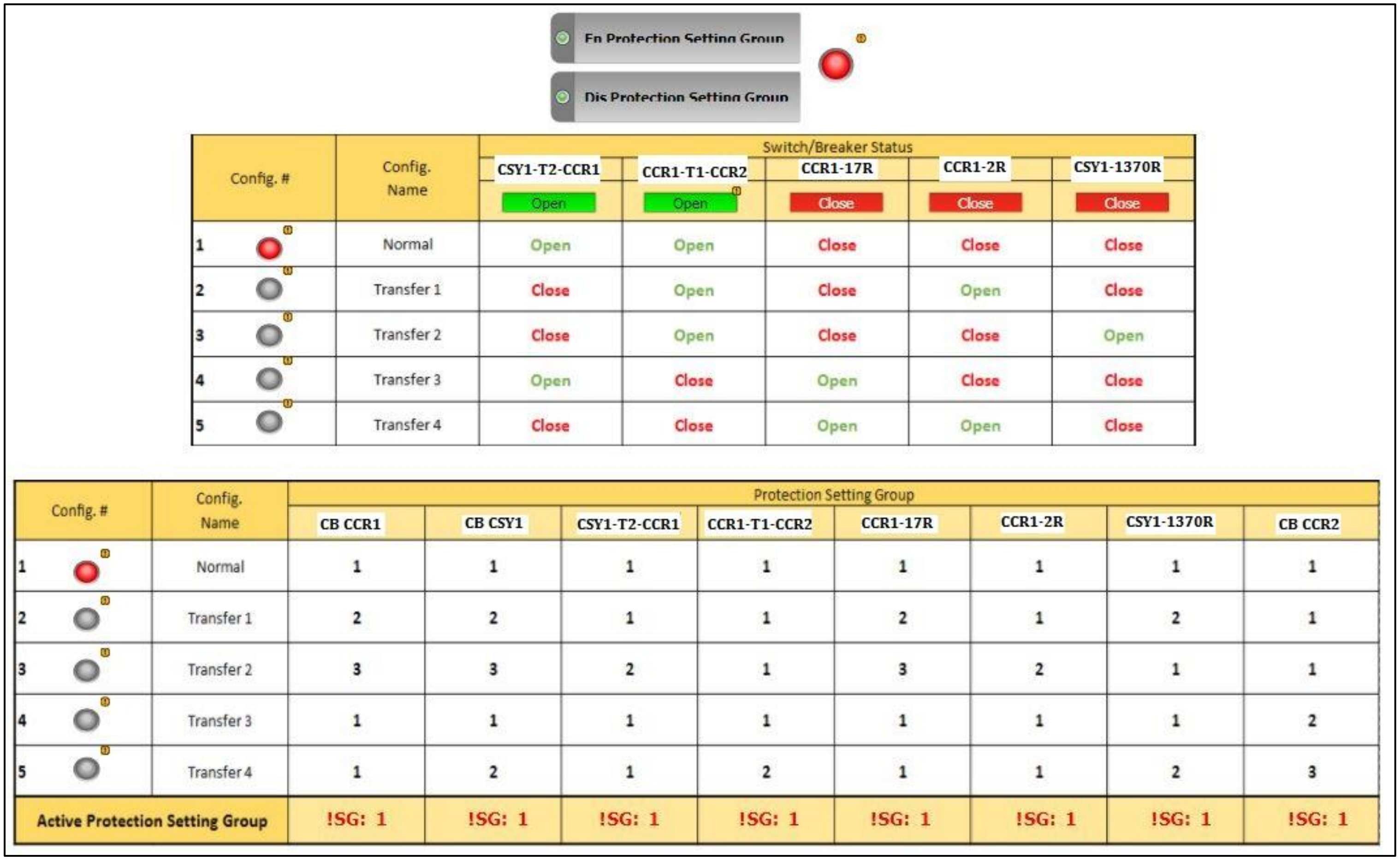


Figure 2-58. Identification of devices referenced in use case 3 test cases

2.4.6.2 Test results

The purpose of this test category was to verify that the master controller and substation controllers would take proper action in response to the system reconfiguration and/or alarms. In particular, it was expected that the protection setting group of certain protective devices would change when the system configuration changed (e.g., due to a load transfer). The performance of the APSC function was evaluated for the same test cases as those considered for the SLT function to ensure proper operation of the application (see Table 2.20 for a list of test cases).

Under normal system configuration (*i.e.*, when all tie switches are open and circuit reclosers are closed), the protection setting groups of all protective relays were set to be at Group 1. This is shown in the first row of both lookup tables in Figure **2-59**. This figure shows that all meaningful system configurations/topologies are listed in a lookup/event table along with the proper protection setting groups for each configuration/topology14. The APSC function was continuously monitoring the states of (major) switching devices in both circuits and performing a real-time matching to determine the most appropriate setting group for the protective devices. For the majority of the test cases of Table 2.20, the system operated with its normal configuration and, thus, the setting group of all devices remained at 1 as shown in Figure 2-59.



Config. #	Config. Name	Switch/Breaker Status				
		CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R
		Open	Open	Close	Close	Close
1	Normal	Open	Open	Close	Close	Close
2	Transfer 1	Close	Open	Close	Open	Close
3	Transfer 2	Close	Open	Close	Close	Open
4	Transfer 3	Open	Close	Open	Close	Close
5	Transfer 4	Close	Close	Open	Open	Close

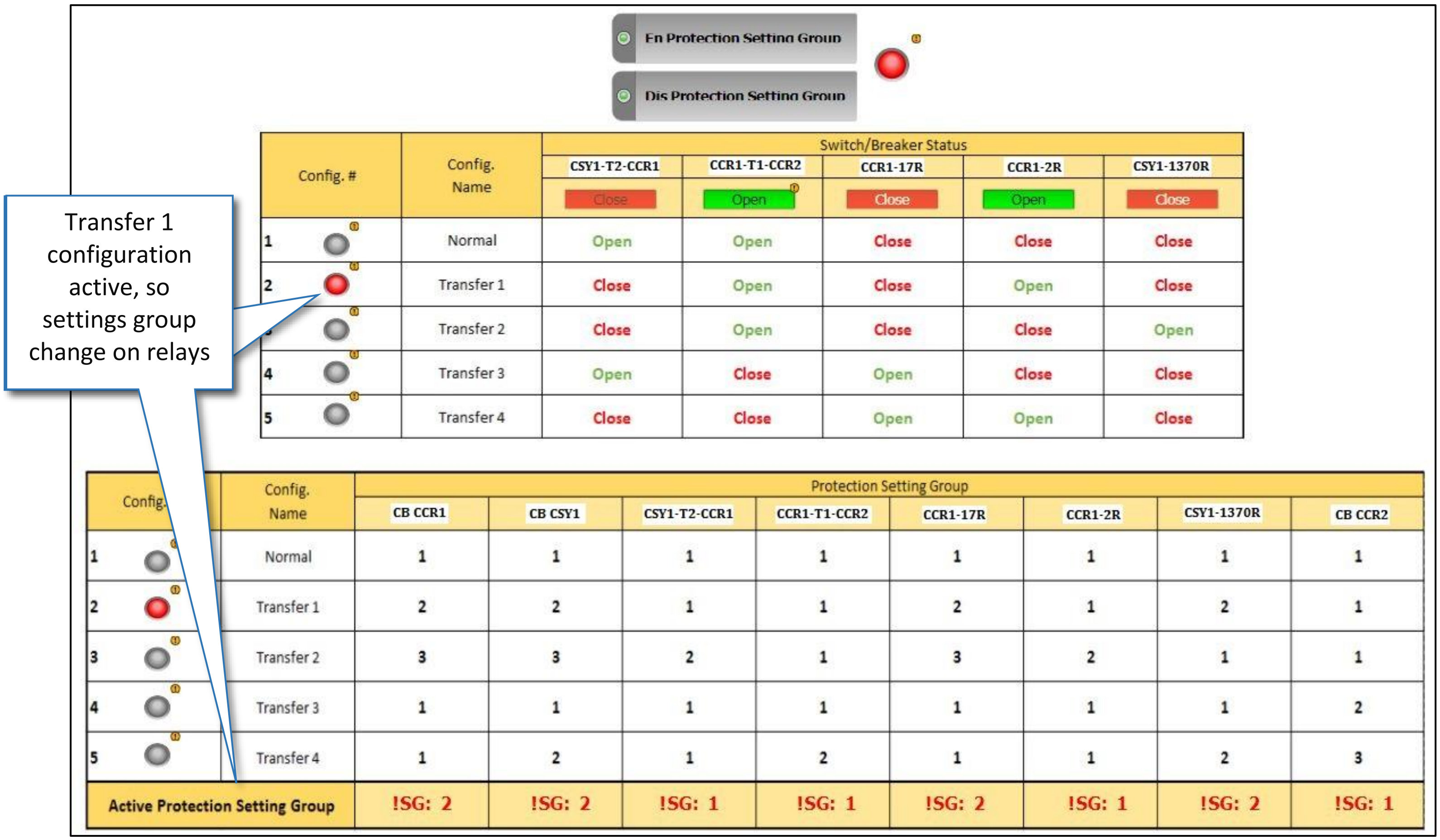
Config. #	Config. Name	Protection Setting Group							
		CB CCR1	CB CSY1	CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R	CB CCR2
1	Normal	1	1	1	1	1	1	1	1
2	Transfer 1	2	2	1	1	2	1	2	1
3	Transfer 2	3	3	2	1	3	2	1	1
4	Transfer 3	1	1	1	1	1	1	1	2
5	Transfer 4	1	2	1	2	1	1	2	3
Active Protection Setting Group		!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1

14 The determination of suitable protection settings for each system topology/configuration is done through a set of off-line fault and protection coordination analyses.

Figure 2-59. Protection setting group of CCR1 and CSY1 devices under normal system configuration (as displayed on Master Controller HMI)

When the system topology/configuration changed (*e.g.*, when the SLT function performed a load transfer and changed the states of some switching devices), the change was detected by the APSC function. This function then found the most appropriate protection setting group for each protective device through a search of the lookup table.

Figure 2-60 shows the selected protection setting group for the system configuration/topology subsequent to the SLT. The figure shows that when the system configuration changed to Transfer 1 (due to the change in the status of CSY1-T2-CCR1 and CCR1-2R), the protection setting group of four protective devices (i.e., CB CSY1, CB CCR1, CCR1-17R, and CSY1-1360R) changed from 1 to 2. It is worth noting that the protection setting group change can also be triggered by a system operator command, *e.g.*, during fire season (not shown in Figure 2-60).



Config. #	Config. Name	Switch/Breaker Status: CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R
		Close	Open	Close	Open	Close
1	Normal	Open	Open	Close	Close	Close
2	Transfer 1	Close	Open	Close	Open	Close
3	Transfer 2	Close	Open	Close	Close	Open
4	Transfer 3	Open	Close	Open	Close	Close
5	Transfer 4	Close	Close	Open	Open	Close

Config. #	Config. Name	Protection Setting Group: CB CCR1	CB CSY1	CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R	CB CCR2
1	Normal	1	1	1	1	1	1	1	1
2	Transfer 1	2	2	1	1	2	1	2	1
3	Transfer 2	3	3	2	1	3	2	1	1
4	Transfer 3	1	1	1	1	1	1	1	2
5	Transfer 4	1	2	1	2	1	1	2	3
Active Protection Setting Group		!SG: 2	!SG: 2	!SG: 1	!SG: 1	!SG: 2	!SG: 1	!SG: 2	!SG: 1

Figure 2-60. Protection setting group of CCR1 and CSY1 devices for transfer 1 configuration (as displayed on master controller HMI).

2.4.7 Distributed control functions

For as long as the master controller was active, the substation controllers were working as gateways, collecting data from downstream IEDs and sending them to the master controller, as well as processing control commands from the master controller and sending them to the downstream IEDs.

However, if the master controller stopped functioning, communications were lost, or control permission was toggled to local control, the substation controllers assumed the control responsibility for their own local area, including the associated substation and the circuits. The logic diagrams for the main control functions for each substation are illustrated in Figure 2-61.

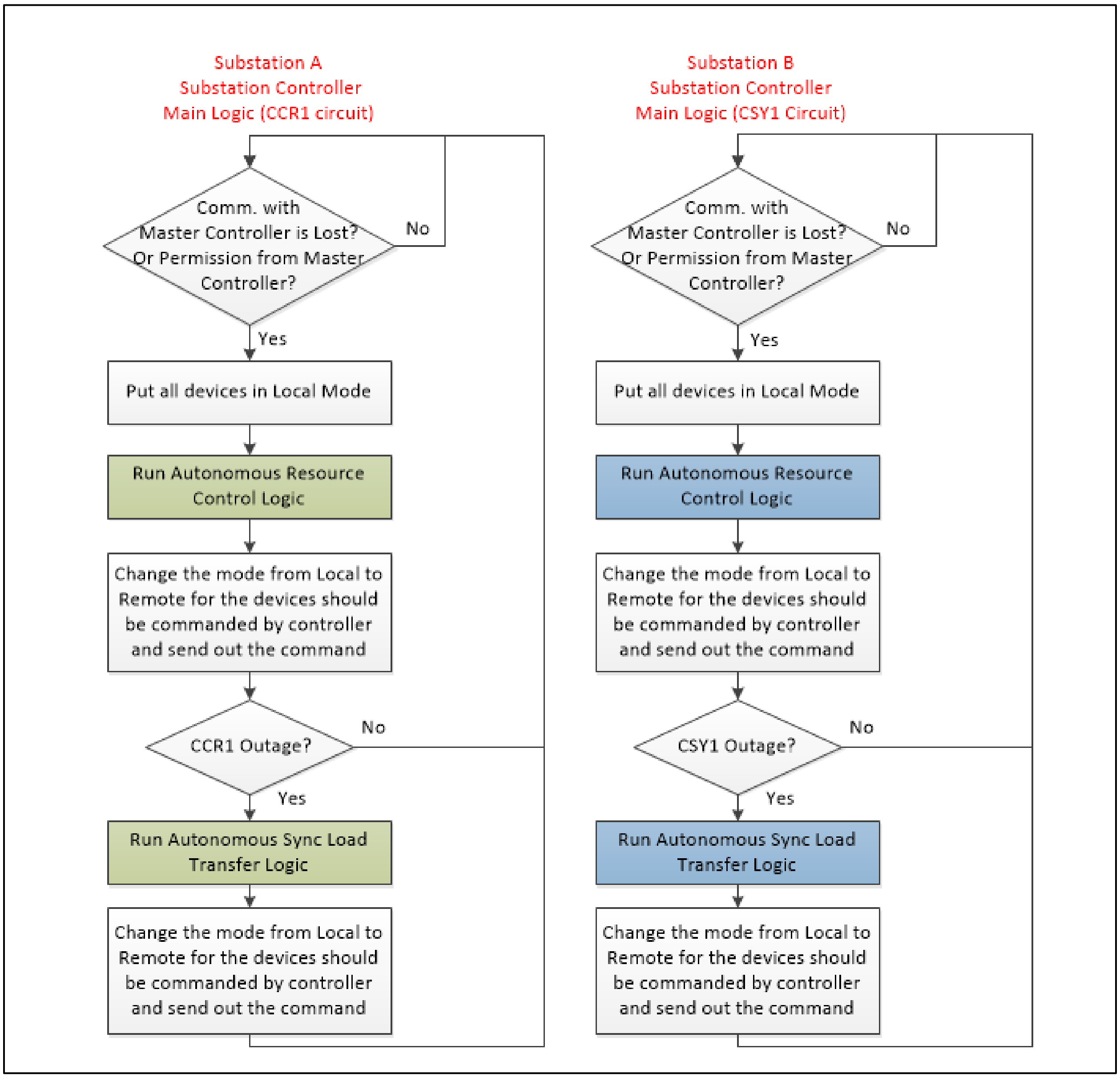


Figure 2-61. Main logic diagrams for each substation controller

Similar to the master controller, there were three control functions in each substation:

- Autonomous Automatic Resource Control (AARC)
- Autonomous Synchronized Load Transfer (ASLT)
- Autonomous Automatic Protection Setting Change (AAPSC)

Since the AAPSC was executed in a very similar manner to the APS (except being performed in substation level), it is not explained again. The following two subsections provides more details on the first two autonomous functions, *i.e.*, AARC and ASLT.

2.4.7.1 Autonomous Automatic Resource Control

Figure 2-62 shows the AARC scheme. In the event of the Master Controller being unavailable, or having issued the appropriate permissions to the substation controllers, logic was initiated in the substation controllers to adjust the active and reactive power generation of the DERs for proper load management.

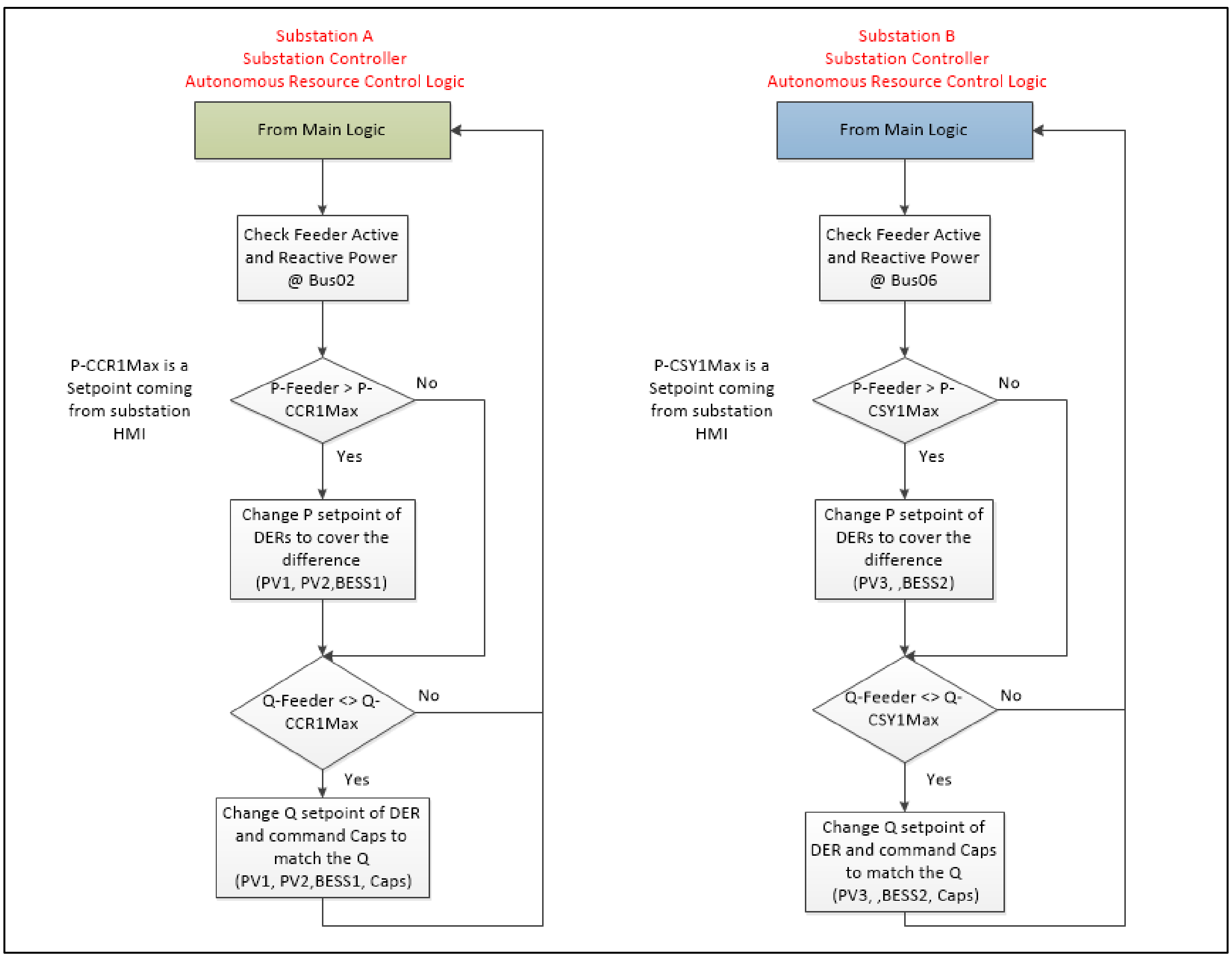


Figure 2-62. Substation Autonomous ARC Logic

The Substation Controllers compared the active and reactive power of the feeder against the maximum active and reactive power setpoints (which could be modified via the Local HMI).

- If the active power of the feeder was more than the maximum power set point, the optimal setpoints for the configured distributed energy resources for each circuit were calculated and transmitted to the appropriate IED controller.
- Reactive power of the feeder was also checked and if different from the Q setpoint, the Q setpoints of the distributed energy resources were changed. The scheme also controlled substation shunt capacitor banks to adjust the reactive power, if needed, in order to maintain power factor at the circuit level.

2.4.7.2 Autonomous Synchronous Load Transfer

Figure 2-63 shows the ASLT logic for each circuit. This logic was designed to serve the loads by monitoring the power flow of recloser R2 and recloser R3 and, if necessary, triggering a load transfer to manage reverse power flow in both circuits.

To perform the load transfer, the Substation Controller sends the sync check command to the tie switch and then waits for a response.

- If the voltages on both sides of the tie switch were in sync, the tie switch controller would close the switch. Subsequently, the upstream isolating switch would be closed by the Substation Controller as soon as the closure confirmation was received from the tie switch.
- If not, the substation controller would receive a sync error message from the tie switch controller. In the event of receiving an unsuccessful sync message from the tie switch, or not hearing back from tie switch within a specific time period, the substation controller would run additional logic to curtail DER resources to prevent reverse power flow, if needed.

It is worth noting that the substation controller would not provide the same level as control as the master controller, mainly due to the limited visibility over the entire system. However, if an adequate communication infrastructure is available and the substation controller has sufficient processing power, it should be able to provide the same control functionality as the master controller.

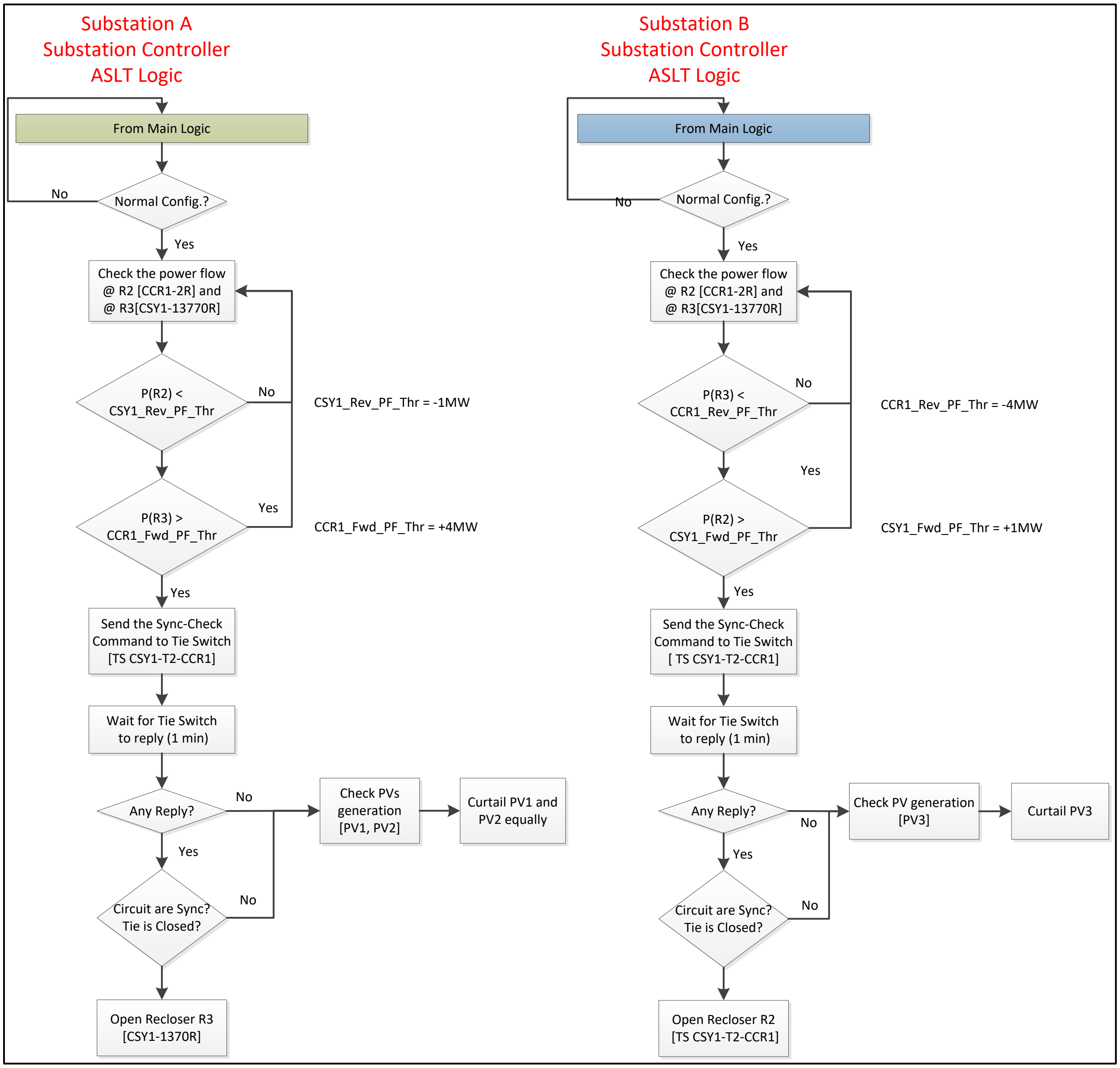


Figure 2-63. Substation Autonomous SLT Logic

3 KEY FINDINGS

This pre-commercial demonstration investigated the implementation of three advanced distribution automation (ADA) applications in a distributed control architecture. The performance of these three ADA applications (use cases) was evaluated through a comprehensive set of tests with actual protection, control, and power hardware devices. To ensure the accuracy of conclusions, three sets of system performance data were analyzed for the assessment of the proposed control architecture. These sets of data were collected for three control scenarios as follows:

- Control scenario 1 (CS 1): No remote control of distribution system resources was available, i.e., capacitor banks, voltage regulators, load tap controllers, smart inverters, and other resources were all working autonomously and in isolation to optimize the portions of the system they could monitor.
- Control scenario 2 (CS 2): Distribution system resources were intelligently controlled by a master controller capable of monitoring and controlling the resources at the two substations modelled in the test system.
- Control scenario 3 (CS 3): Distribution system resources were intelligently controlled by the substation controllers for each of the substations, autonomously and with limited access to each other.

The results of this project showed that although a multi-tiered control architecture is required for a distributed control system, such a design offers several advantages over conventional control schemes commonly used in distribution systems. The following paragraphs discuss a summary for the three different use cases.

3.1 Automatic Resource Control

The test results for ARC use case proved conclusively that intelligent control of distribution system resources improves system performance. They demonstrated that a master controller with the ability to control and monitor multiple substations that are electrically interconnected provides the greatest amount of benefit (CS 2). They furthermore confirmed that even when the control is limited to a single substation and downstream distribution system resources (CS 3), significant improvements in system performance are recognized in contrast to the case where there is no remote control (CS 1).

Several performance criteria were defined and analyzed to accurately evaluate the performance of a distributed control approach. The following conclusion was made throughout the course of this study:

- The response time of the control system significantly improves when the distribution controllable resources can be remotely controlled by an engine embedding an optimal (or semi-optimal) control logic, *i.e.*, CS 2 and CS 3.
- In almost all cases, the system voltage profile was improved under CS 2 and CS 3. In particular, the voltage profile can be regulated more precisely through fine tuning of DER setpoints.
- Optimized remote control of DERs (CS 2 and CS 3) can reduce the system losses through enhanced contribution of DERs.
- Under CS 2 and CS 3, DERs provide more reactive power support which, in turn, enables accurate adjustment of the power factor (e.g., close to unity) at the circuit or substation level.
- The cumulative number of controllable asset operation decreases under CS 2 and CS 3, due to the increased contribution of DERs as well as enhanced system observability (control coordination). However, since master/substation Controller aims at optimal voltage regulation, there were some test cases that show minimum or no improvement in the total asset operations.

- With CS 2 and CS 3 in place, DER integration into distribution system can be facilitated. In other words, intelligent remote control of DERs can address some of the challenges associated with high penetration of DERs.
- Implementing a distributed control approach requires a minimum communication infrastructure being available to enable remote control of distribution resources. In addition, the distribution voltage regulators, capacitor bank controllers, IEDs, etc. should support a standard communication protocol. These are considerations that need to be taken into account for developing a distributed control architecture in distribution systems.
- Some of the existing DERs in the field do not support smart inverter features and control modes. As an example, the battery used in this study does not support remote power factor adjustment and V-Q droop modes. In the proposed control architecture, it is essential that certain DERs to support specific control modes.

Table 3.1 below provides a summary of findings for test cases 1.10, 1.11 and 1.12, which were explained in Section 2.4.4.2. The dark cells show improvement while the lighter shaded cells indicate no enhancement. The results for the remaining test cases are captured in Appendix A.

Table 3.1. Summary of ARC test results

Parameter	Scenario 1 Result	Delta between Scenarios 1 and 2	Delta between Scenarios 1 and 3
Maximum voltage magnitude (rms)	8.04 kV (1.16pu)	7% less	5% less
Maximum out-of-range value with respect to maximum allowable voltage (rms)	765.4 V (0.11pu)	78% less	48% less
Out-of-range duration (seconds)	115 seconds	78% less	30% less
Power Loss	1.04MW	26% less	17% less
Active Power (DER Involvement/Contribution)	31.8 kW	4% less	3% less
Asset Operations	52 operations	35% less	6% more

Improvement
No improvement

3.2 Synchronized Load Transfer

The Synchronized Load Transfer (SLT) is a unique ADA application that can help with load and power flow management in distribution systems dominated with DERs. Conventional control techniques in distribution systems cannot manage reverse power flow without curtailing renewable DERs. The SLT provide the possibility of transferring the partial load/generation to another circuit while the maximum energy is extracted from renewable resources.

The SLT tests were able to show that the master controller and substation controllers could collectively perform load transfer between two circuits from two different substations when excessive reverse power flow was measured along the feeder, *e.g.*, when the DER penetration/injection was high. More importantly, the transfer is performed while the system is energized, that is, with no customer interruption. The following is the main findings and recommendations for the SLT use case:

- SLT is an effective solution to reverse power flow management under high penetration of DERs, with the maximum power being obtained from renewable resources.
- SLT will resolve the reverse power issue without any interruption being imposed to customers.
- The SLT requires the voltage on both sides of the tie switch to be cophasal. If this condition is not met, the SLT can command some of the controllable assets to bring the voltages (magnitudes) to an acceptable range. However, the control of voltage phase angles is not an easy task and, in some cases, it is impossible. Nonetheless, it is acknowledged that the synchronization criterion for voltage phase angle in distribution systems is most of the time met (no violation was observed during the course of this project).
- To ensure a smooth transition during a transfer, it is recommended that the master/substation controller takes some corrective actions prior to the SLT initiation, based on the Near-Real-Time Power flow analysis. This was not systematically studied in this project (beyond the project scope), but try and error showed potential for further improvement during the transition.

3.3 Automatic Protection Setting Change

The requirements for performance improvement of the protection system under different system conditions and/or configurations has led to the idea of Automatic Protection Setting Change (APSC). The APSC tests demonstrated that protection settings could be dynamically changed to adapt to changing system configurations triggered by unplanned system events or ARC and SLT system re-configurations. The following is the main findings and recommendations for the SLT use case:

- The APSC can ensure that the system is always protected regardless of the system topology, DER penetration level, and prevailing DER statuses.
- The real-time matching algorithm of the APSC is easily and fully implementable in both master controller and substation controller.
- The proposed APSC algorithm need offline studies to be run for all meaningful system configurations/conditions in order to calculate proper protection settings. This may potentially become a time-consuming task, considering that new system configurations/conditions will be frequently introduced to the system with the increasing penetration of DERs and application of new ADA applications.
- Fuses, electromechanical relays, and standard solid-state relays that are common in distribution systems do not provide the flexibility of changing protection settings, limiting the efficiency of the APSC. Digital (microprocessor-based) relays with flexible protection settings as well as communication capabilities are required for the APSC. The trend of utilizing of advanced digital relays is expected to address this concern in the future.

4 RECOMMENDATIONS AND NEXT STEPS

As detailed in the preceding sections, the use cases comprehensively demonstrated that real, quantifiable benefits are achieved when a distributed control scheme is implemented that allows high-speed, localized control of IEDs and DER in substations and feeders.

As such, the concept deserves additional investigations in the field and real-world environment. It is recommended that SDG&E plan and implement a pilot project to test real-world performance of the distributed controls as the next step. Although not part of this project, the use of the IEC 61850 communication standard holds the promise of allowing data exchange between substations without central SCADA intervention, thereby offering additional opportunities for system optimization. The pilot project should be planned such that sufficient time exists to work through any real-world and interoperability issues. Aside from exploring the deployment of the technology, the pilot project should have several other objectives:

- Quantify costs and benefits, and then develop a cost-benefit analysis for wide scale deployment
- Examine what changes to standard operating procedures are necessary to fully leverage the benefit of the distributed control system design.
- Use the pilot project as a training platform for engineering and operational personnel

The integration of feeder-based IEDs and DERs is more complex than for those inside the substation boundary, and high-speed and reliable communications are a prerequisite.

Hence, it is recommended that the pilot project also explorer various communication technologies and allow for real-world testing. Additional testing on a carefully selected substation and feeder combination and the results analyzed over a period of time will ensure the maturity of the technology is such that system performance is consistent and reliable.

The project provided a good platform for SDG&E personnel to increase their familiarity with the different technologies. It is recommended that as far as possible, the same team remain engaged in the pilot projects to build upon the experience gained to date.

It is recommended that this project be followed by the development of a strategic roadmap for deployment of distributed controls which identifies ADMS functions that can be implemented in substation and feeder based controllers.

4.1 Technology/Knowledge transfer plan for applying results into practice

During the course of the project, several workshops and project demonstration sessions were held with the involvement of SDG&E stakeholders to share the project approach, major findings and to showcase the specific use cases.

SDG&E plans to communicate the results of the project with the industry at large. It is therefore recommended that appropriate venues such as conferences and industry events be selected for paper submission and presentation to summarize and share the key findings with the industry. By doing so, the experience gained on this project can be shared with as many stakeholders as possible – which includes anyone dealing with the need to integrate DERs and other IEDs on the distribution system. SDG&E will also widely announce the availability of this final report.

5 METRICS AND VALUE PROPOSITION

5.1 Project Metrics

The project tracking metrics included the milestones in the project plan. Technical metrics for this project were based on comparing the performance of distribution system operations when various new control schemes are in place with the performance of the same operations when the control schemes are not in place. These performance metrics included measures of power quality, electrical loss reductions, asset health maintenance, and adaptability to new device types in the distribution system.

Also, major project results were submitted as technical papers and presentations for consideration by major technical conferences and publications.

The following metrics were identified for this project:

- **Economic benefits:**
    a. Reduction in electrical losses in the transmission and distribution system.
    b. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear.
    c. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management.

- **Safety, Power Quality, and Reliability (Equipment, Electricity System):**
    a. Outage number, frequency and duration reductions.
    b. Forecast accuracy improvement.
    c. Reduced flicker and other power quality differences.
    d. Increase in the number of nodes in the power system at monitoring points.

- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy:**
    a. Description of the issues, project(s), and the results or outcomes.
    b. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
    c. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360).

- **Effectiveness of information dissemination:**
    a. Number of information sharing forums held.
    b. Stakeholders attendance at workshops.
    c. Technology transfer.

- **Adoption of EPIC technology, strategy, and research data/results by others**
    a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards.

5.2 Value Proposition: Primary and Secondary Guiding Principles

The value proposition was to address how the project met the EPIC principals.

Table 5.1 summarizes the specific primary and secondary EPIC principles advanced by the Distributed Control for Smart Grids Project:

Table 5.1: EPIC Primary and Secondary Guiding Principles

Primary Principals			Secondary Principals				
Reliability	Lower Costs	Safety	Loading Order	Low-Emission Vehicles / Transportation	Safe, Reliable & Affordable Energy Sources	Economic Development	Efficient Use of Ratepayers Monies
✓		✓					

The Distributed Control for Smart Grids Project covers the following primary EPIC principals:

- **Reliability:** The results of this project demonstrates several scenarios and options that dynamically adjust protection settings to increase reliability. The demonstrated benefits of the distributed control approach in the areas of DER integration, improved grid stability, reliability and power quality and better utilization of controllable assets.

- **Safety:** The project focuses on a decentralized control approach, which gives for faster response times and deterministic behavior improves personnel safety, since there will be less intervention and therefore less room for human error.

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7 LIST OF ACRONYMS AND ABBREVIATIONS

AAPSC	Autonomous Automatic Protection Setting Change
AARC	Autonomous Automatic Resource Control
ADA	Advanced Distribution Automation
ADCS	Advanced Distributed Control System
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AP	Application Processor
APS	Automatic Protection Setting
APSC	Automatic Protection Setting Change
ARC	Automatic Response Control
ASLT	Autonomous Synchronized Load Transfer
BESS	Battery Energy Storage System
CT	Current Transformer
DA	Distribution Automation
DCS	Distributed Control System
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
D-SCADA	Distribution SCADA
DMS	Distribution Management System
DRMS	Demand Response Management System
DSO	Distribution System Operator
EMS	Energy Management System
EPIC	Electric Program Investment Charge
ESS	Energy Storage Systems
FAT	Factory Acceptance Test
FIT	Feeder Injection Test
FLISR	Fault Location, Isolation, and Service Restoration
HIL	Hardware-in-Loop
HMI	Human Machine Interfaces
IEC	International Electrotechnical Corporation
IED	Intelligent Electronic Device
ITF	SDG&E’s Integrated Test Facility
kW	Kilowatt
LTC	Load Tap Changer
NRTPF	Near-Real-Time Power Flow

OMS	Outage Management System
PCC	Point of Common Coupling
PHIL	Power Hardware in the Loop
PMU	Phasor Measurement Unit
PT	Potential Transformer (aka Voltage Transformer)
PV	Photovoltaic
RFP	Request for Proposal
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SIL	Software-in-Loop
SLD	Single Line Diagram
SLT	Synchronized Load Transfer
VR	Voltage Regulator

8 APPENDIX A – ADDITIONAL USE CASE RESULTS

Both Use Case 1 and Use Case 2 involved several test cases, but for the sake of brevity, only a representative sample of these were evaluated in the preceding sections. Appendix A documents the results of those test cases that were omitted from the earlier sections. While the test results are not explained in detail in this section, they enable the interested reader to observe the difference between various control scenarios.

The figures that follow illustrate the locations of the various SLD elements referenced in the test cases, as well as the mapping on how values like the P and Q contributions of the DER on the two circuits are constructed.

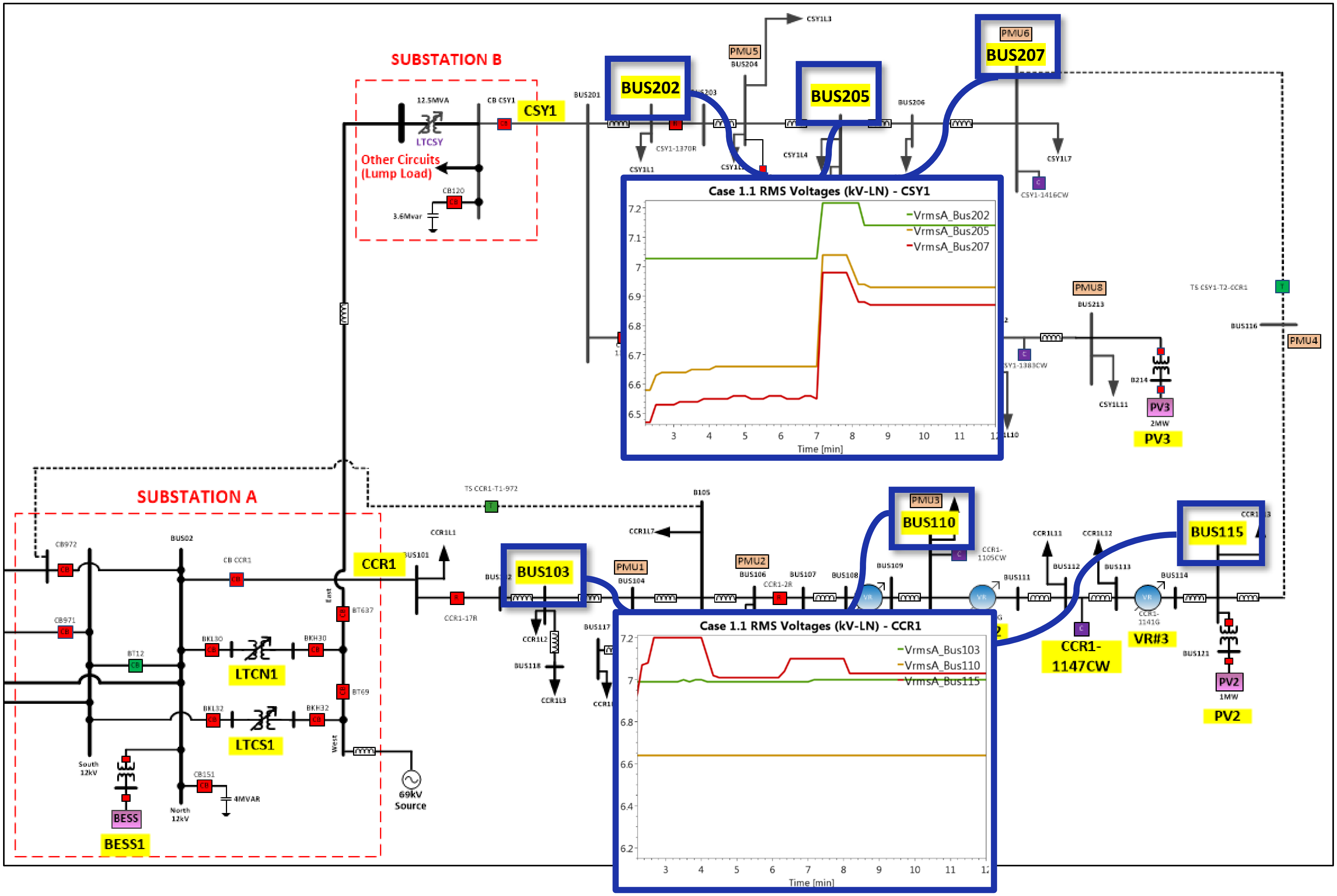

Figure 8-1. Mapping of SLD elements to test case charts (RMS Voltage)

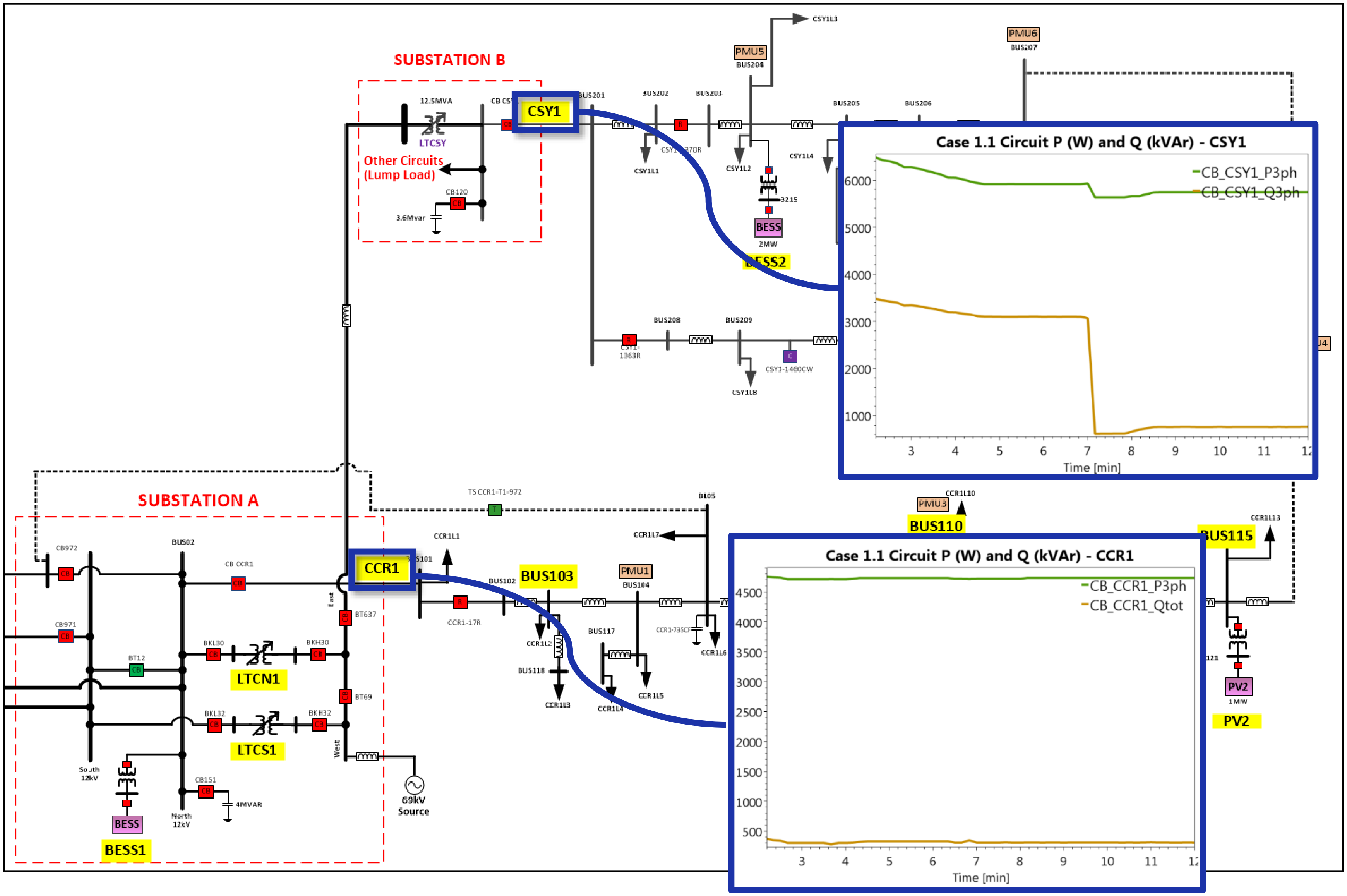

Figure 8-2. Mapping of SLD elements to test case charts (Reactive power)

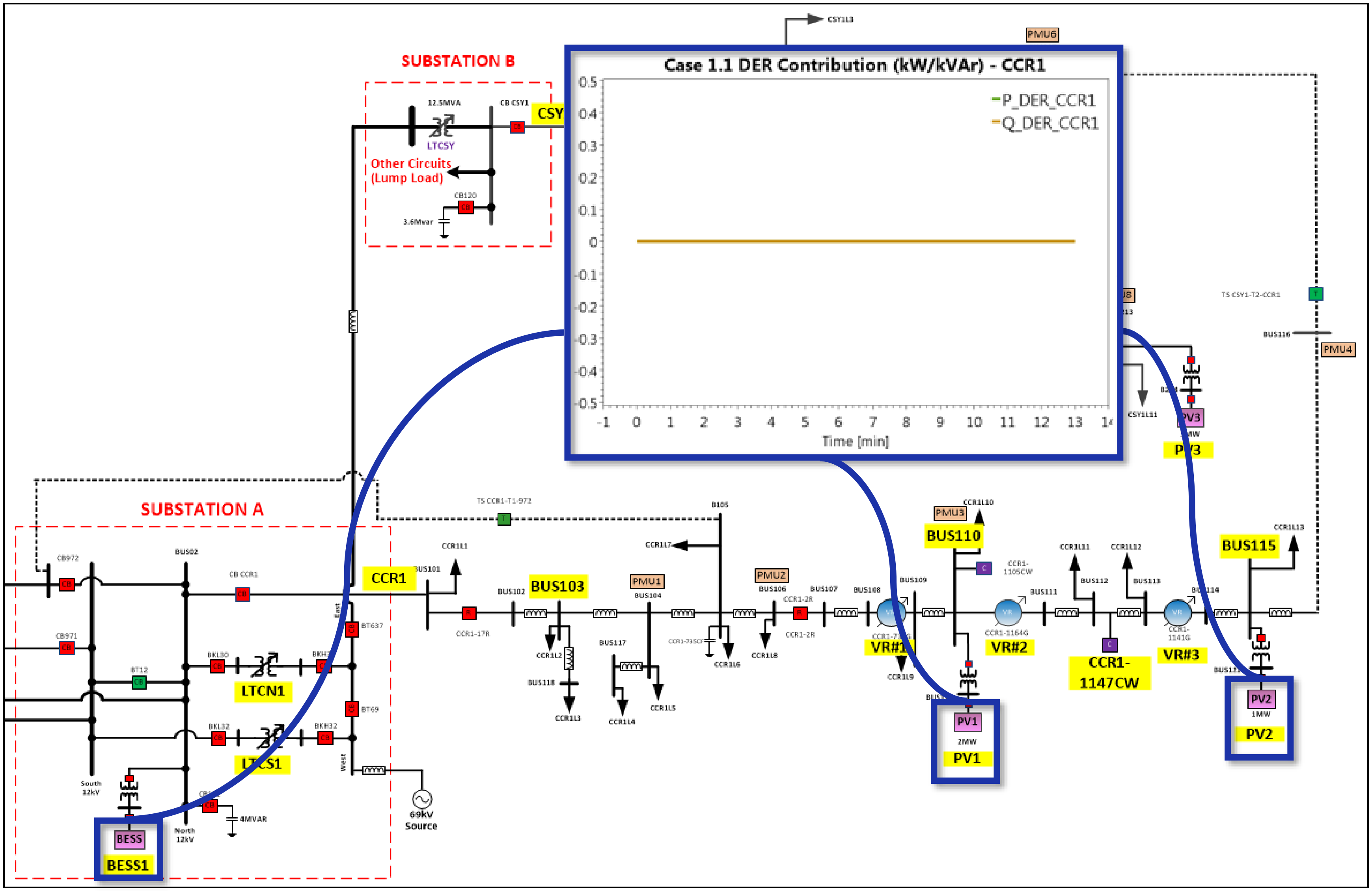

Figure 8-3. Mapping of SLD elements to test case charts (DER on CCR1)

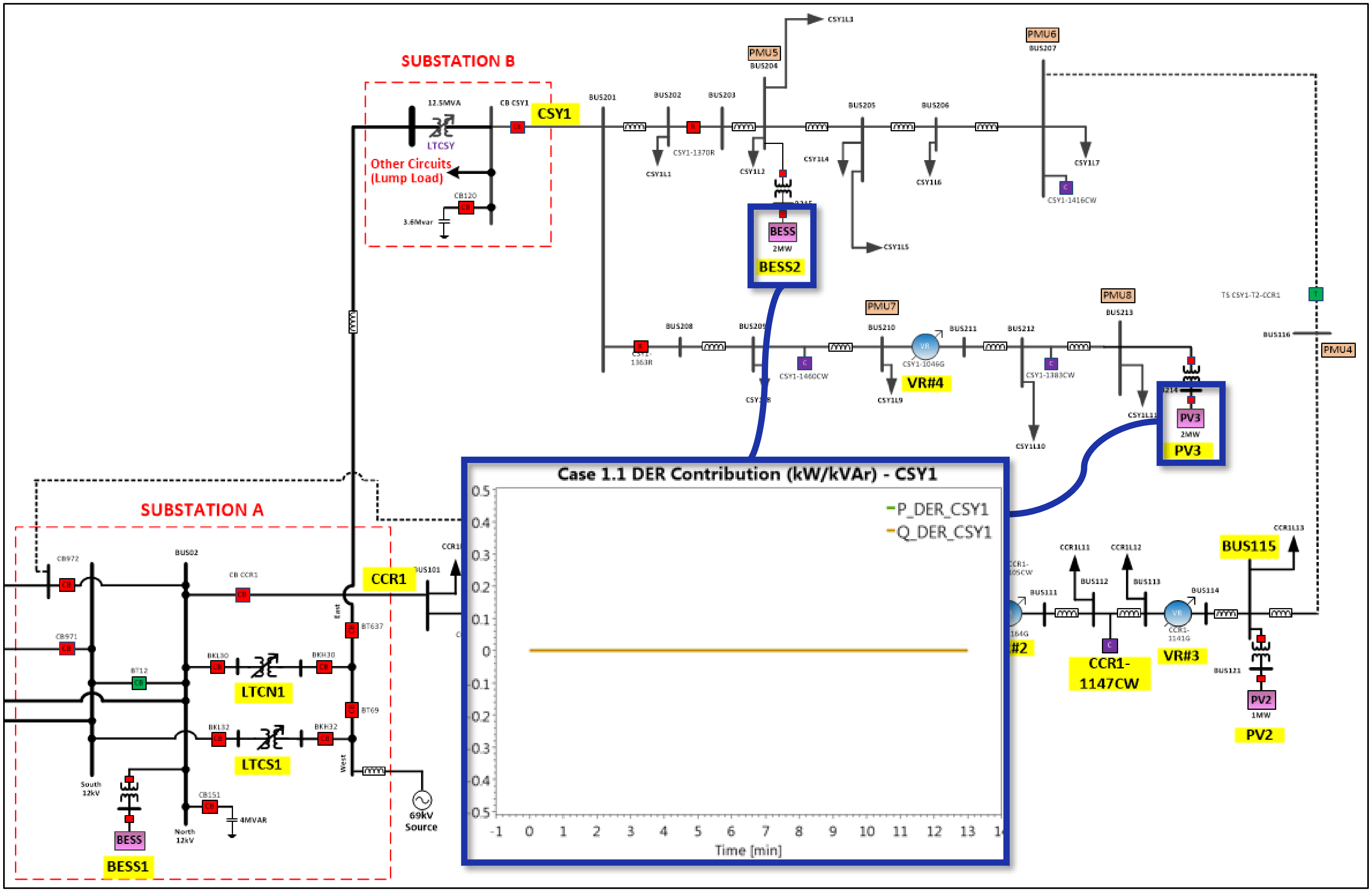

Figure 8-4. Mapping of SLD elements to test case charts (DER on CSY1)

8.1 Use Case 1: Automatic Resource Control Test Results

8.1.1 Test Case 1.1

Table 8.1. Test condition for Case 1.1

Case#	Test Conditions	Remark
1.1	High load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)

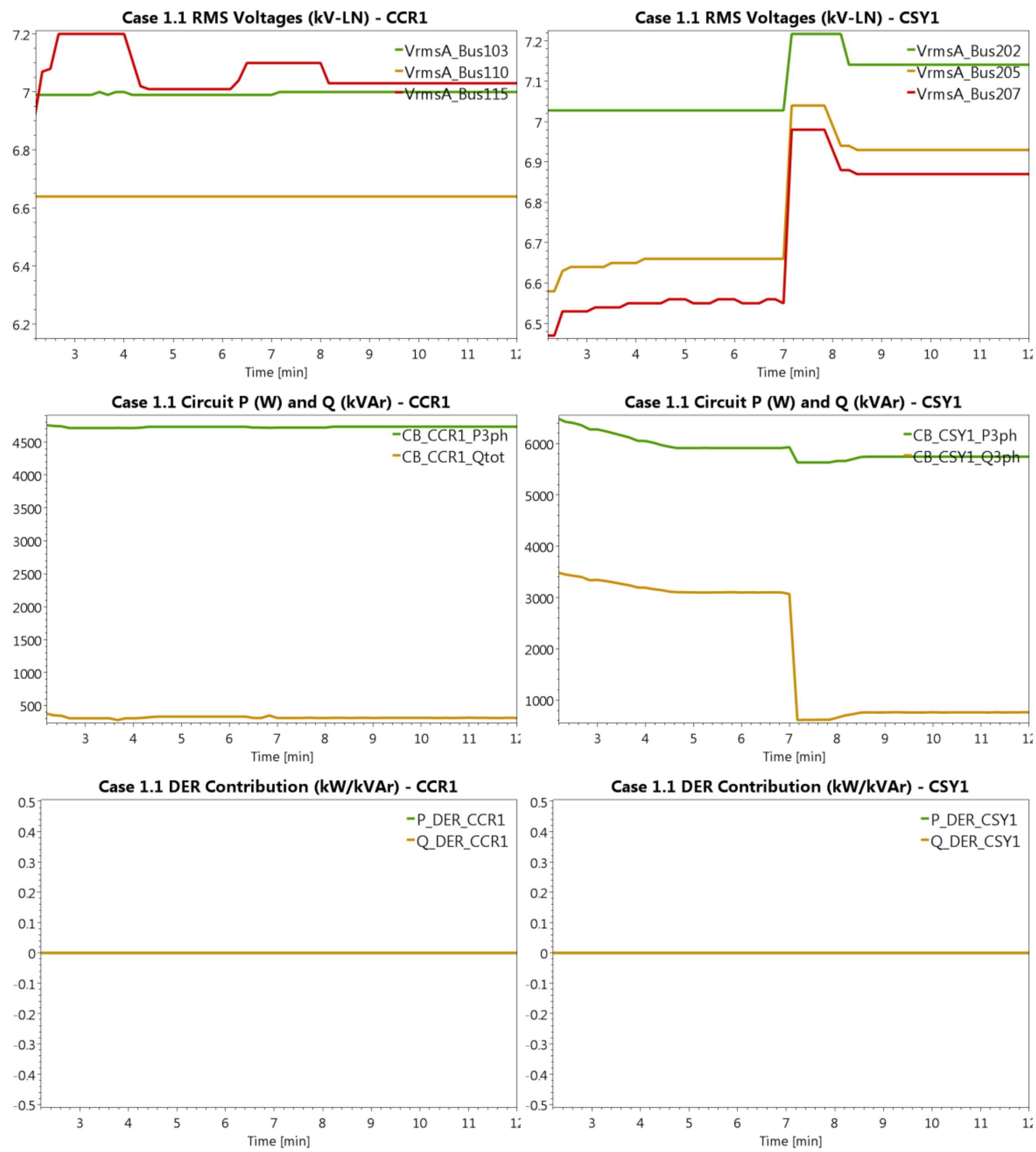

Figure 8-5. Voltage profiles, circuit powers, and DER contributions for Case 1.1

It can be observed in Figure 8-5 that, under CS1 (Local Control Scenario), BESSs do not contribute to the regulation of the voltage profile.

8.1.2 Test Case 1.2

Table 8.2. Test condition for Case 1.2

Case#	Test Conditions	Remark
1.2	High load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Master controller was responsible to take actions through ARC/IVVC algorithm.

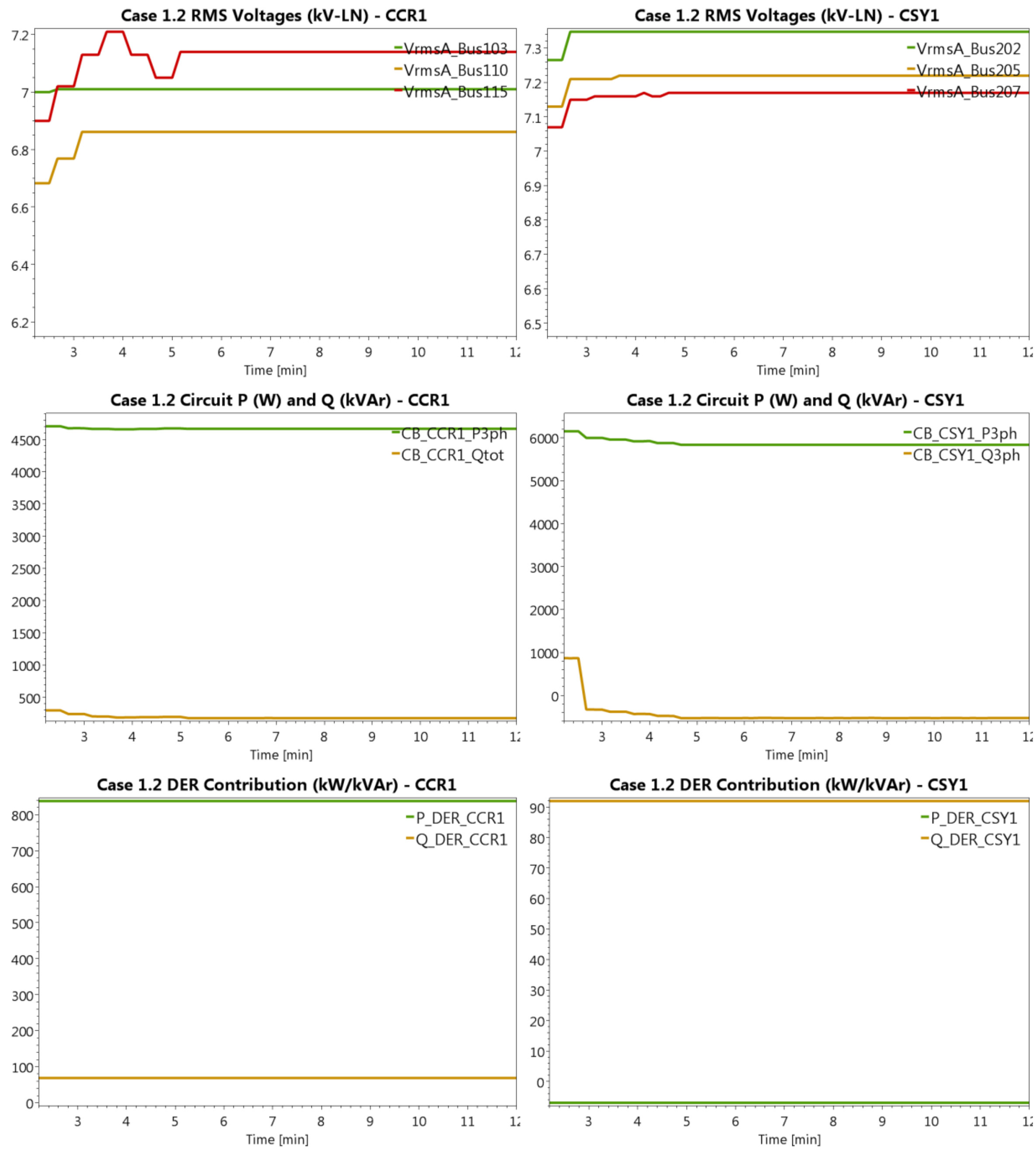

Figure 8-6. Voltage profiles, circuit powers, and DER contributions for Case 1.2

Figure 8-6 shows that the master controller involves BESSs in the adjustment of bus voltages (CS2), thereby leading to an improved voltage regulation and circuit power factor (as compared to Case 1.1).

8.1.3 Test Case 1.3

Table 8.3. Test condition for Case 1.3

Case#	Test Conditions	Remark
1.3	Low load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)

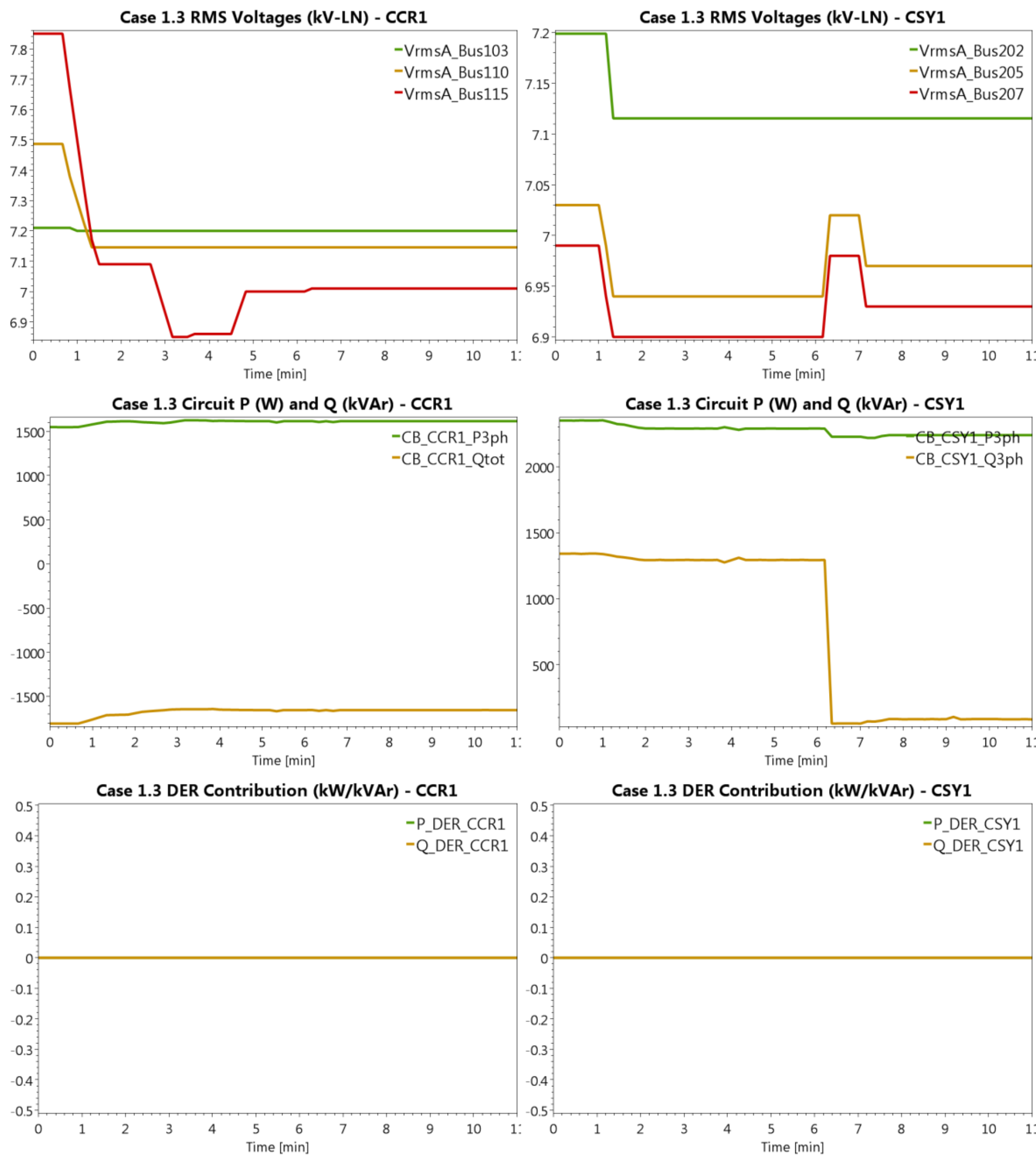

Figure 8-7. Voltage profiles, circuit powers, and DER contributions for Case 1.3

Similar to Case 1.1, BESSs are not involved in the voltage regulation and, thus, the bus voltages experience a jump as shown in Figure 8-7. This may cause unintentional operation of some of the protective equipment. Further, the circuit power factors are not improved.

8.1.4 Test Case 1.4

Table 8.4. Test condition for Case 1.4

Case#	Test Conditions	Remark
1.4	Low load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Master controller was responsible to take actions through ARC/IVVC algorithm.

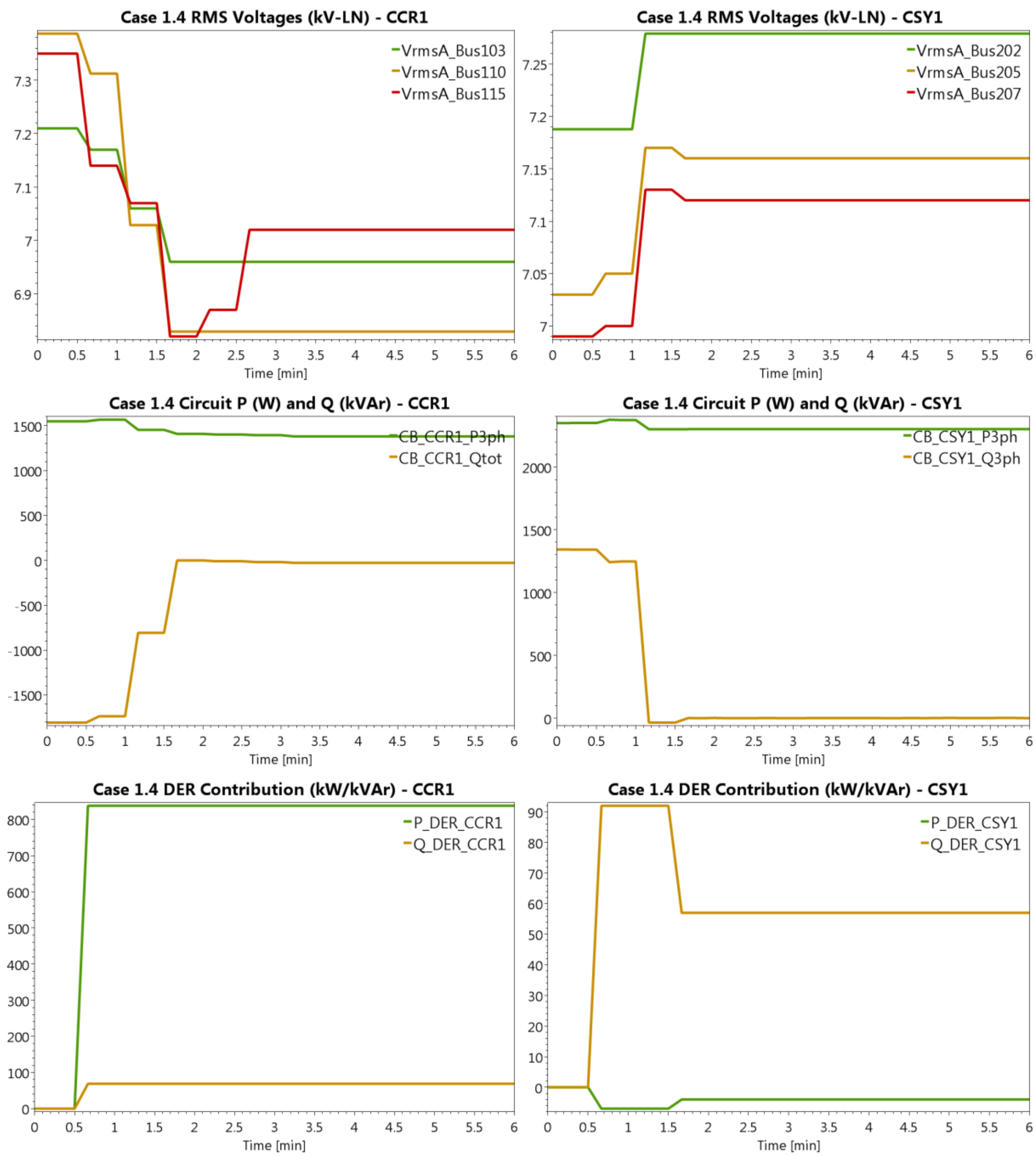

Figure 8-8. Voltage profiles, circuit powers, and DER contributions for Case 1.4

The master controller utilizes BESSs for system performance improvement. As such, besides the fine tuning of bus voltages, the increased contribution of DERs improves system efficiency and power factor.

8.1.5 Test Case 1.5

Table 8.5. Test condition for Case 1.5

Case#	Test Conditions	Remark
1.5	High load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.1	Baseline System 2 (all controllable devices were in Local/Auto mode)

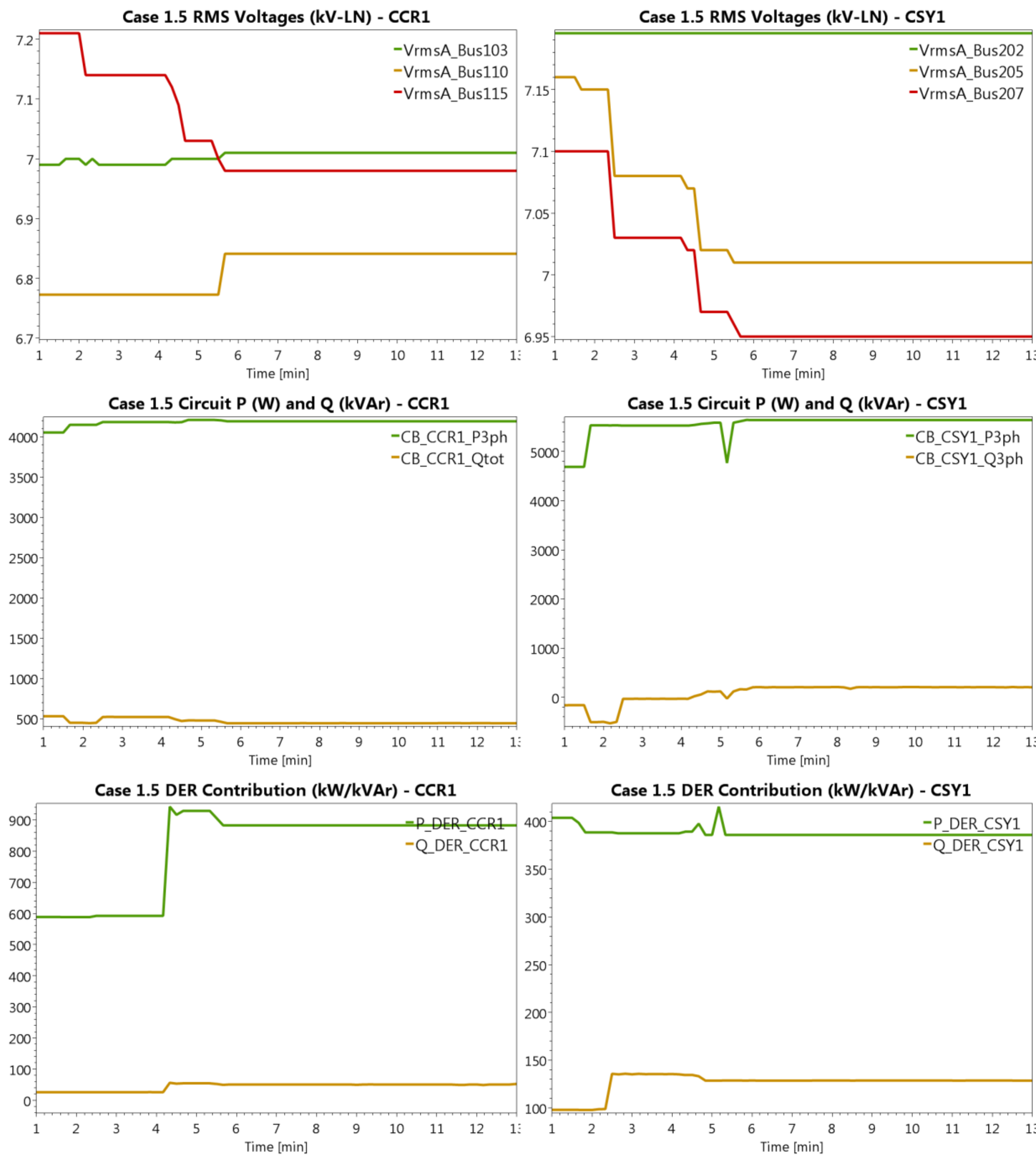

Figure 8-9. Voltage profiles, circuit powers, and DER contributions for Case 1.5

Figure 8-9 shows that the substation BESS has generated some real power based on its local peak shaving functionality.

8.1.6 Test Case 1.6

Table 8.6. Test condition for Case 1.6

Case#	Test Conditions	Remark
1.6	High load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.1	Master controller was responsible to take actions through ARC/IVVC algorithm.

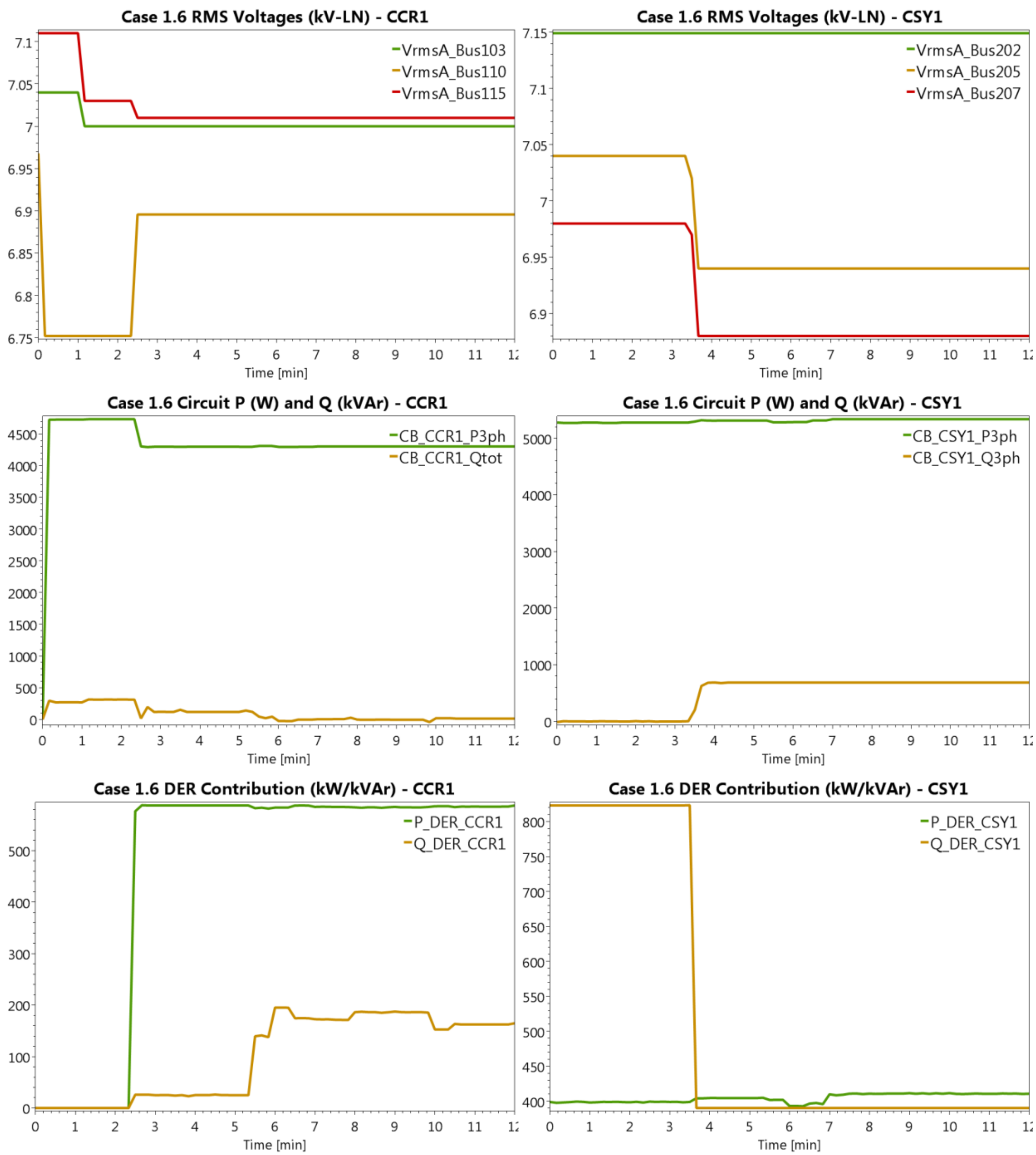

Figure 8-10. Voltage profiles, circuit powers, and DER contributions for Case 1.6

Compared to Case 1.5, the voltage profile has been improved due to the effective utilization of DERs. It is also noted that voltage control has had more priority over the feeder power factor regulation.

8.1.7 Test Case 1.7

Table 8.7. Test condition for Case 1.7

Case#	Test Conditions	Remark
1.7	High load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.1	Sub controller was responsible to take actions through permission or communication loss (prior to event)

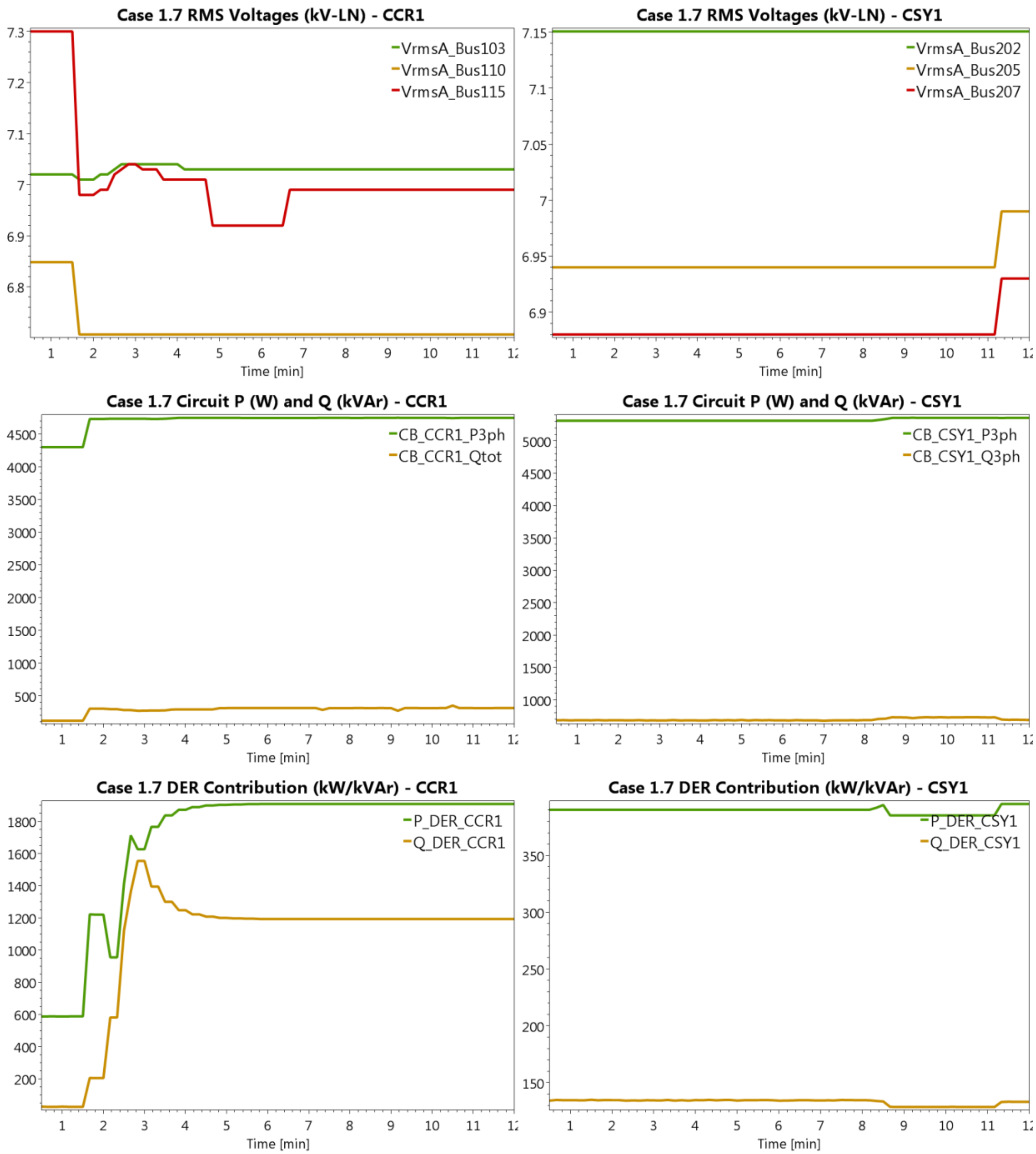

Figure 8-11. Voltage profiles, circuit powers, and DER contributions for Case 1.7

The results of Figure 8-11 shows that, for this test case, the substation controller is able to regulate the bus voltages and feeder power factor almost similar to the master controller (Case 1.6).

8.1.8 Test Case 1.8

Table 8.8. Test condition for Case 1.8

Case#	Test Conditions	Remark
1.8	Case 1.5: High load (fix), Low PV (fix) Trip CCR1-1147CW after the system gets to the steady state condition.	Baseline System 2 (all controllable devices were in Local/Auto mode)

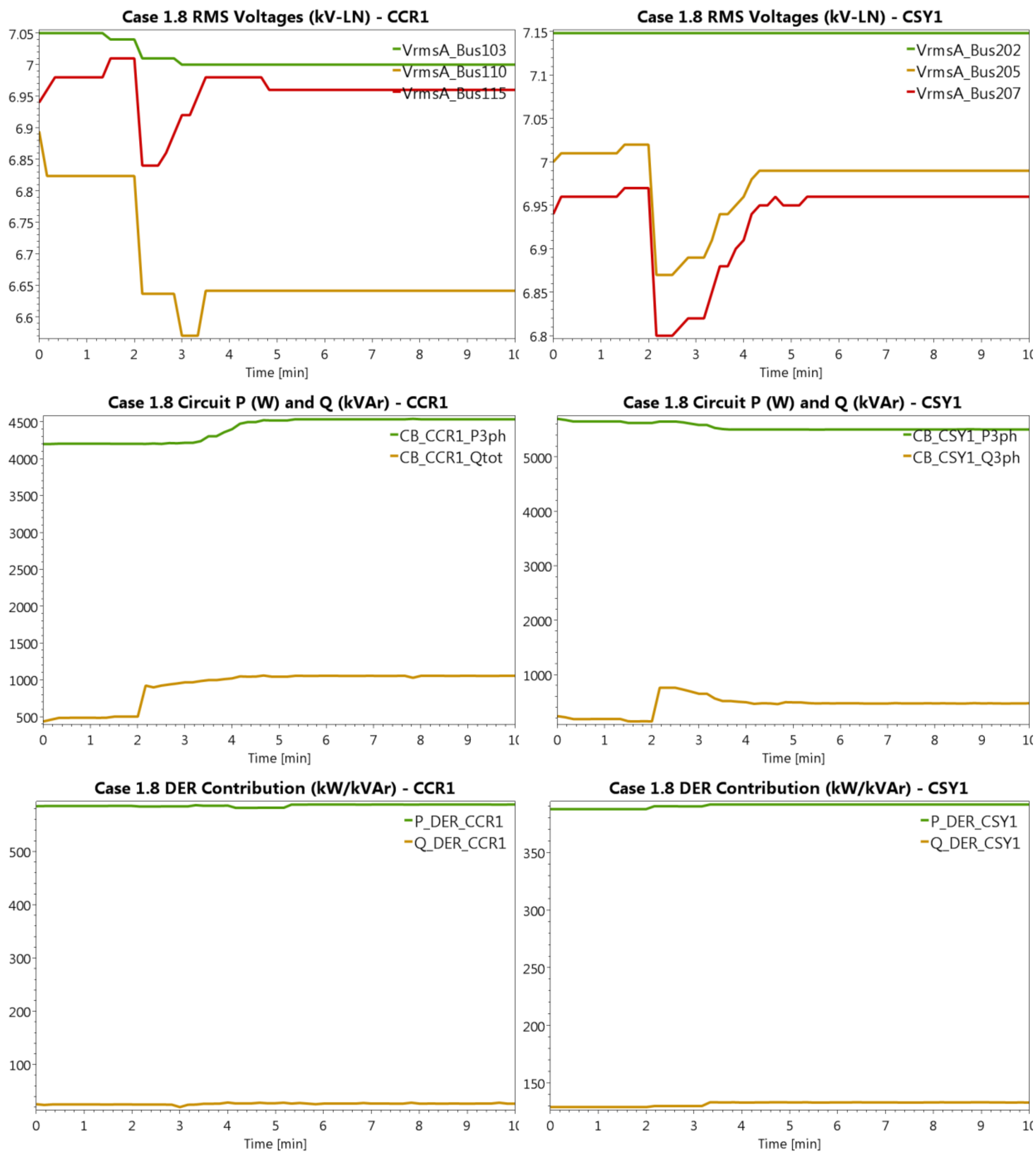

Figure 8-12. Voltage profiles, circuit powers, and DER contributions for Case 1.8

As can be seen in Figure 8-12, following the cap bank trip, the local controllers cannot bring back the voltage of Bus 110 to the acceptable range. It is also observed that DERs have minimal involvement.

8.1.9 Test Case 1.9

Table 8.9. Test condition for Case 1.9

Case#	Test Conditions	Remark
1.9	Case 1.6: High load (fix), Low PV (fix) TripCCR1-1147CW after the system gets to the steady state condition.	Master controller was responsible to take actions through ARC/IVVC algorithm.

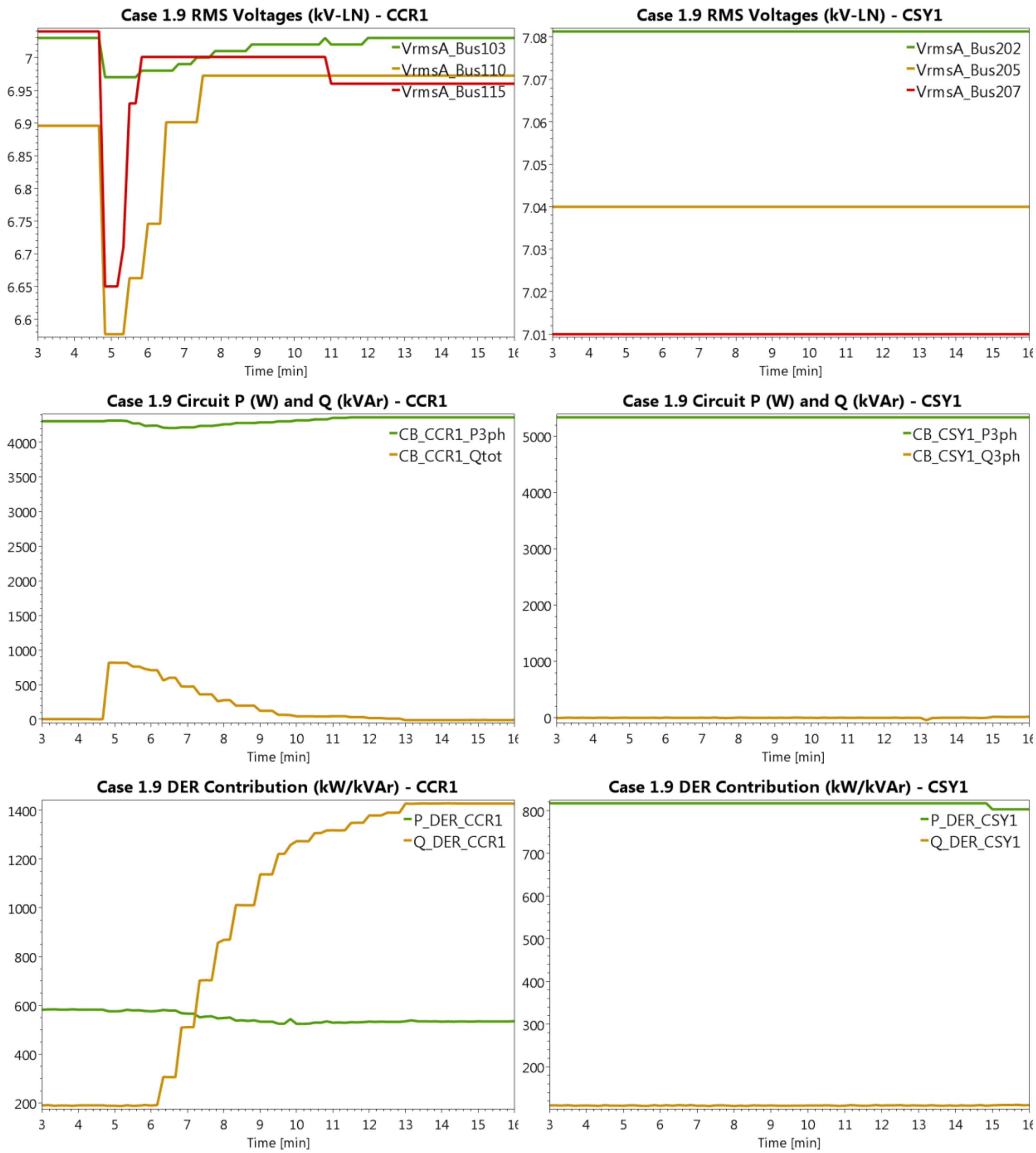

Figure 8-13. Voltage profiles, circuit powers, and DER contributions for Case 1.9

As opposed to Case 1.8, the master controller effectively utilizes DERs to regulate voltage profile and improve power factor, while minimizing the renewable energy curtailment.

8.1.10 Test Case 1.15

Table 8.10. Test condition for Case 1.15

Case#	Test Conditions	Remark
1.15	Low load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

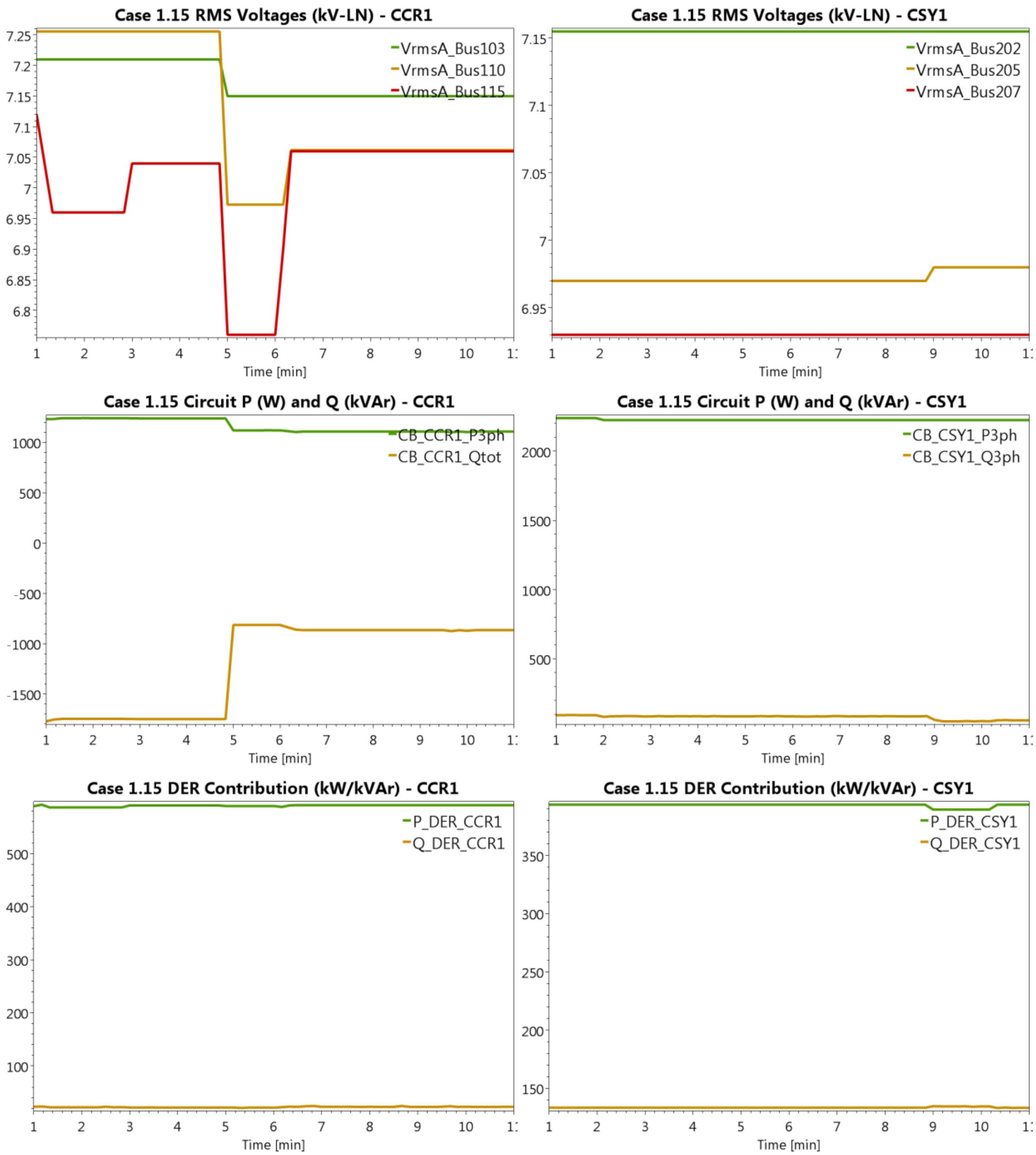

Figure 8-14. Voltage profiles, circuit powers, and DER contributions for Case 1.15

As shown in Figure 8-14, due to the lack of coordination among local controllers, the voltage of buses fluctuate considerably. Also, the capacitor bank has operated late (about 5 min after the PV profile change).

8.1.11 Test Case 1.16

Table 8.11. Test condition for Case 1.16

Case#	Test Conditions	Remark
1.16	Low load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through ARC/IVVC algorithm.

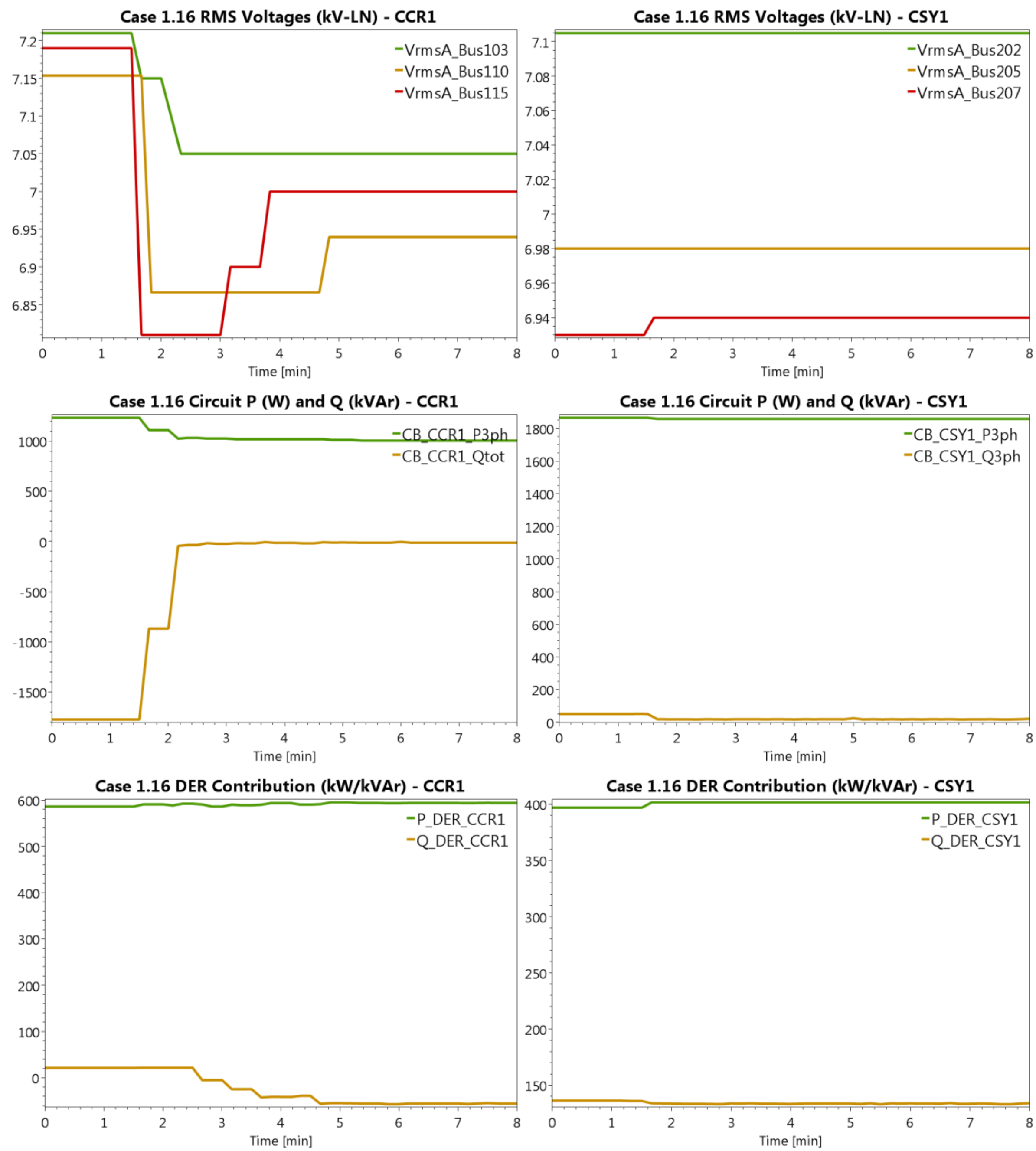

Figure 8-15. Voltage profiles, circuit powers, and DER contributions for Case 1.16

Figure 8-15 shows that the master controller trips a capacitor bank to improve both feeder power factors, while keeping the bus voltages within the acceptable range (enhanced DER involvement).

8.1.12 Test Case 1.17

Table 8.12. Test condition for Case 1.17

Case#	Test Conditions	Remark
1.17	Low load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission or communication loss (prior to event)

Figure 8-16. Voltage profiles, circuit powers, and DER contributions for Case 1.17

Under CS3 (substation controller in charge), the voltage profiles are improved (compare to Case 1.15), but the feeder power factors are not as good as Case 1.16 (master controller in charge).

8.1.13 Test Case 1.18

Table 8.13. Test condition for Case 1.18

Case#	Test Conditions	Remark
1.18	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

Figure 8-17. Voltage profiles, circuit powers, and DER contributions for Case 1.18

Figure 8-17 shows that, subsequent to the PV profile change, the system undergoes severe transients due to uncoordinated actions of various controllers (including local control of DERs).

8.1.14 Test Case 1.19

Table 8.14. Test condition for Case 1.19

Case#	Test Conditions	Remark
1.19	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through ARC/IVVC algorithm.

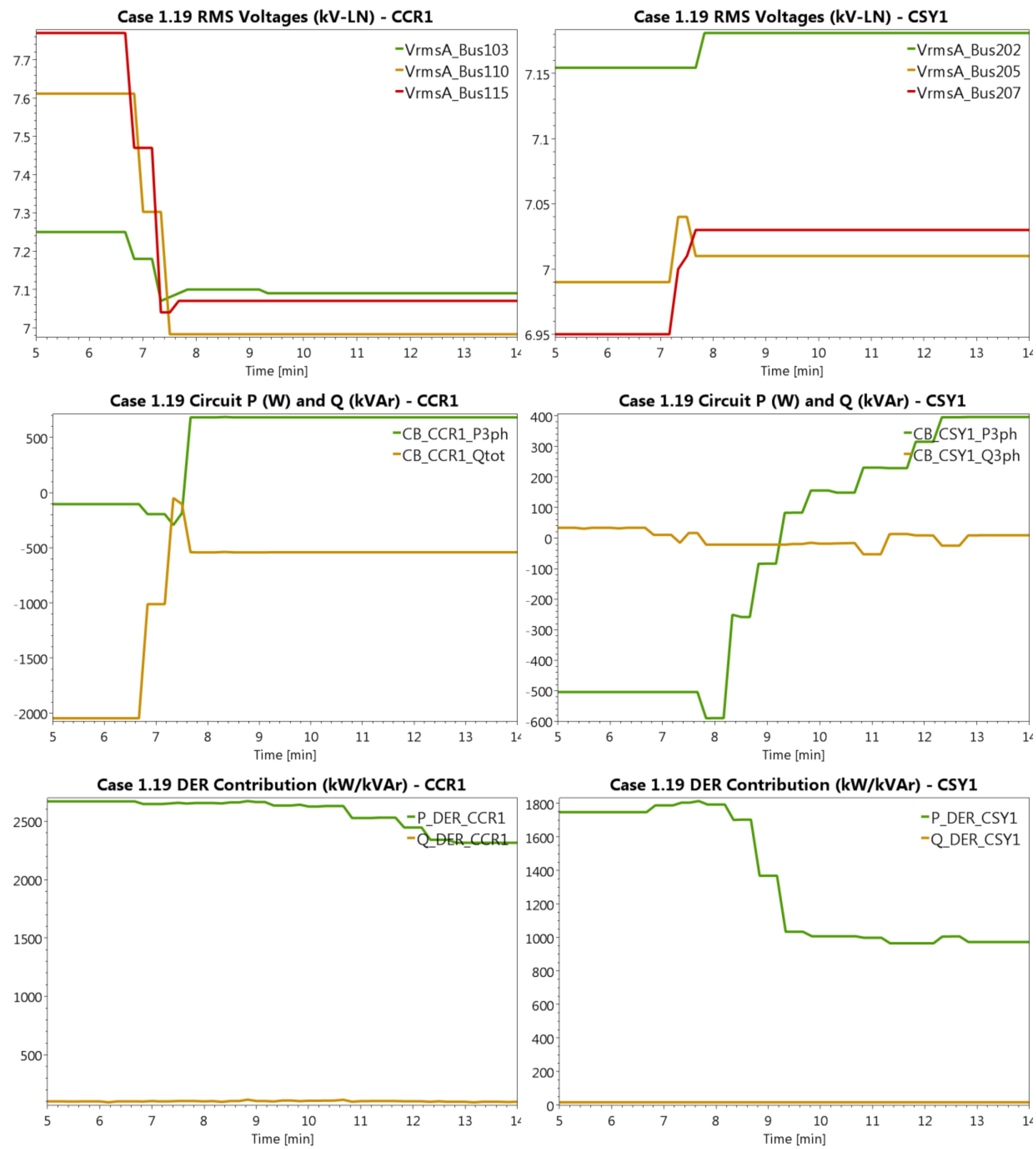

Figure 8-18. Voltage profiles, circuit powers, and DER contributions for Case 1.19

Compared to Case 1.18, the master controller has been able to effectively stabilize the system operating conditions while managing reverse power flow at the feeder circuit breakers.

8.1.15 Test Case 1.20

Table 8.15. Test condition for Case 1.20

Case#	Test Conditions	Remark
1.20	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission or communication loss (prior to event)

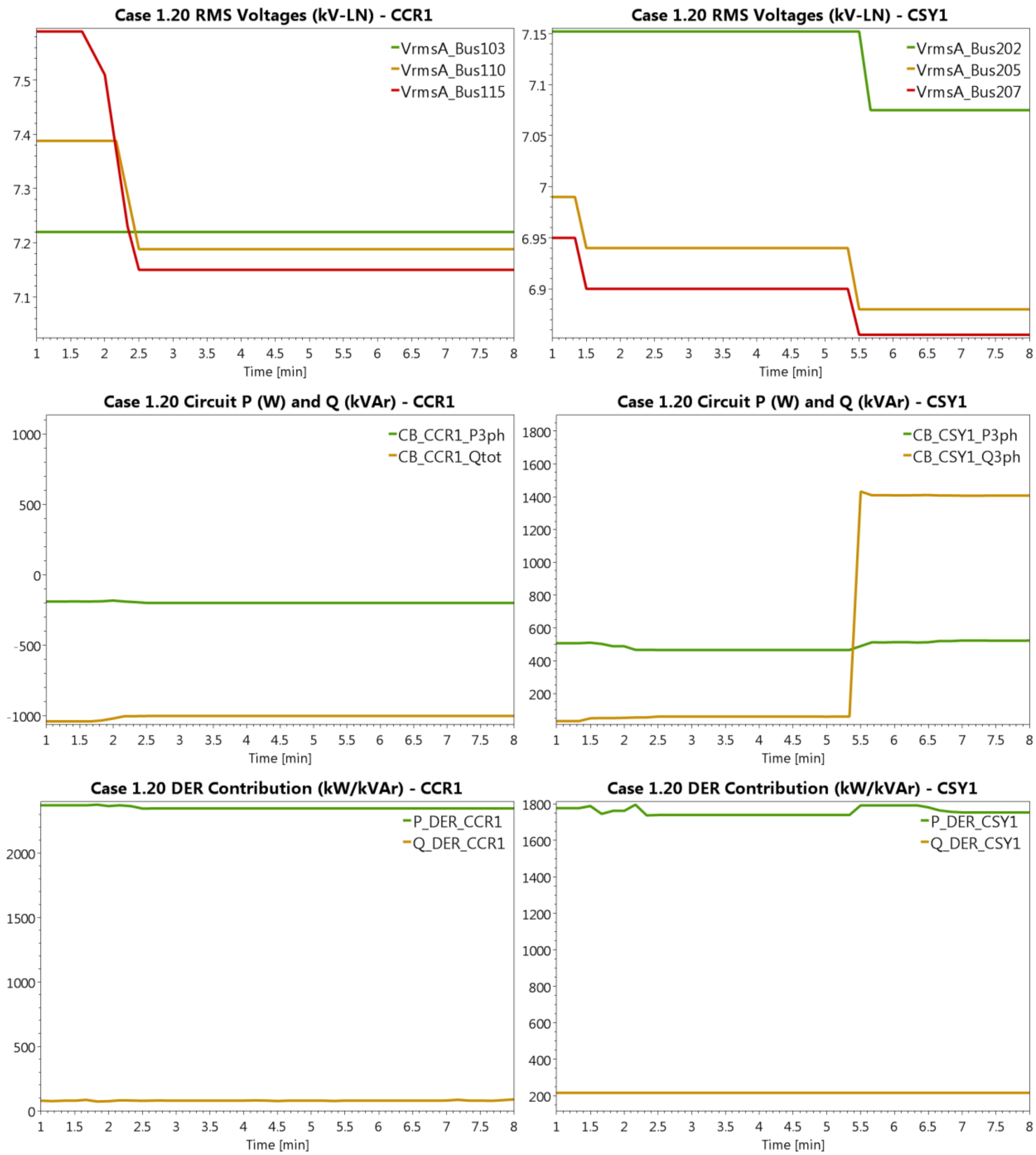

Figure 8-19. Voltage profiles, circuit powers, and DER contributions for Case 1.20

While the voltage profiles are improved in this case (compare to CS1 – Case 1.18), the substation control cannot effectively enhance DER contributions to improve both system efficiency and power factor.

8.1.16 Test Case 1.21

Table 8.16. Test condition for Case 1.21

Case#	Test Conditions	Remark
1.21	Case 1.15: Low load (fix), High PV (fix) Trip PVs after the system gets to the steady state condition.	Baseline System 2 (all controllable devices were in Local/Auto mode)

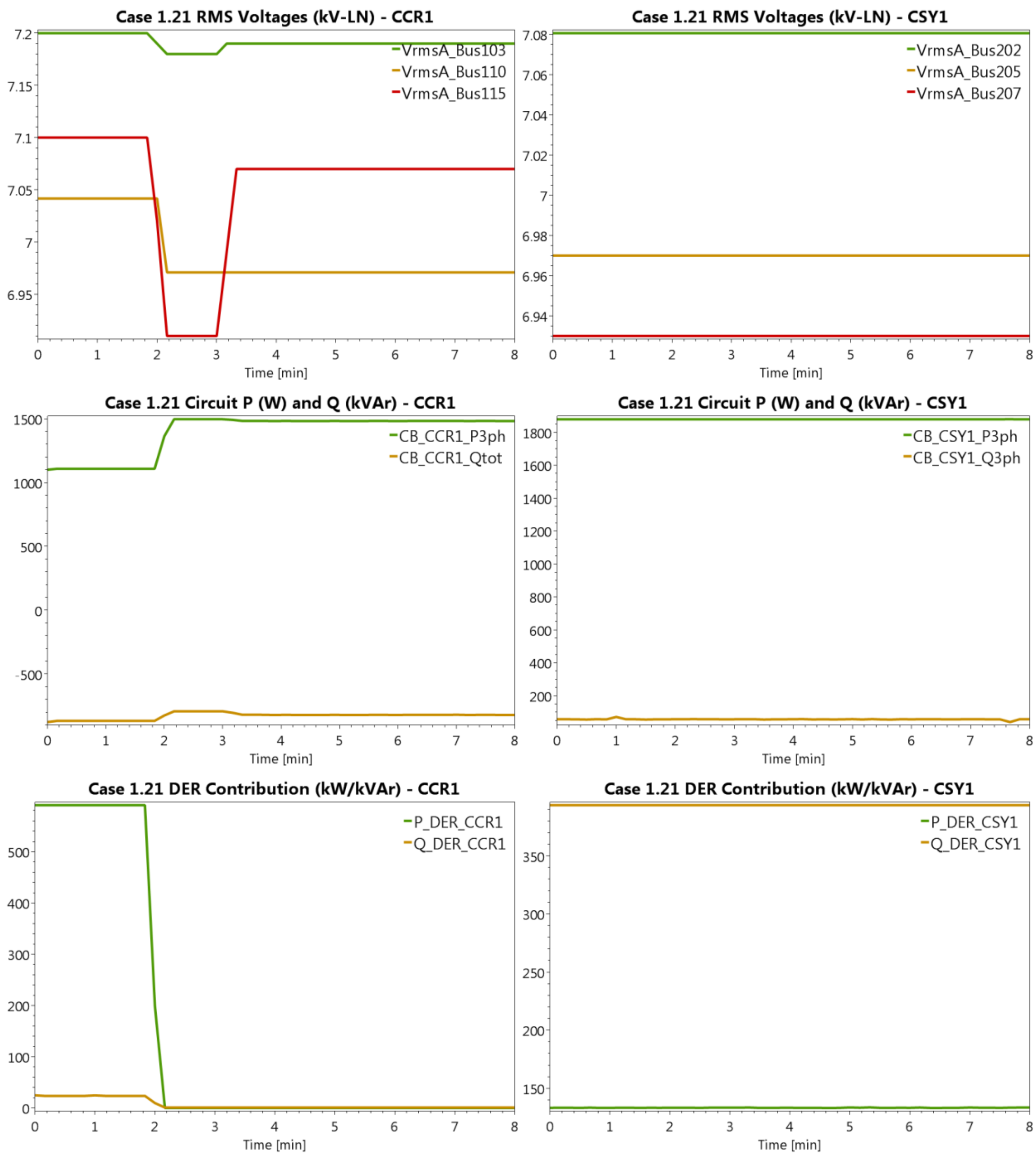

Figure 8-20. Voltage profiles, circuit powers, and DER contributions for Case 1.21

Figure 8-20 shows that the PV trips did not impact the voltage profile significantly. However, the local controllers could not optimize the feeder power factors.

8.1.17 Test Case 1.22

Table 8.17. Test condition for Case 1.22

Case#	Test Conditions	Remark
1.22	Case 1.16: Low load (fix), High PV (fix) Trip PV 1 after the system gets to the steady state condition.	Master controller is responsible to take actions through ARC/IVVC algorithm.

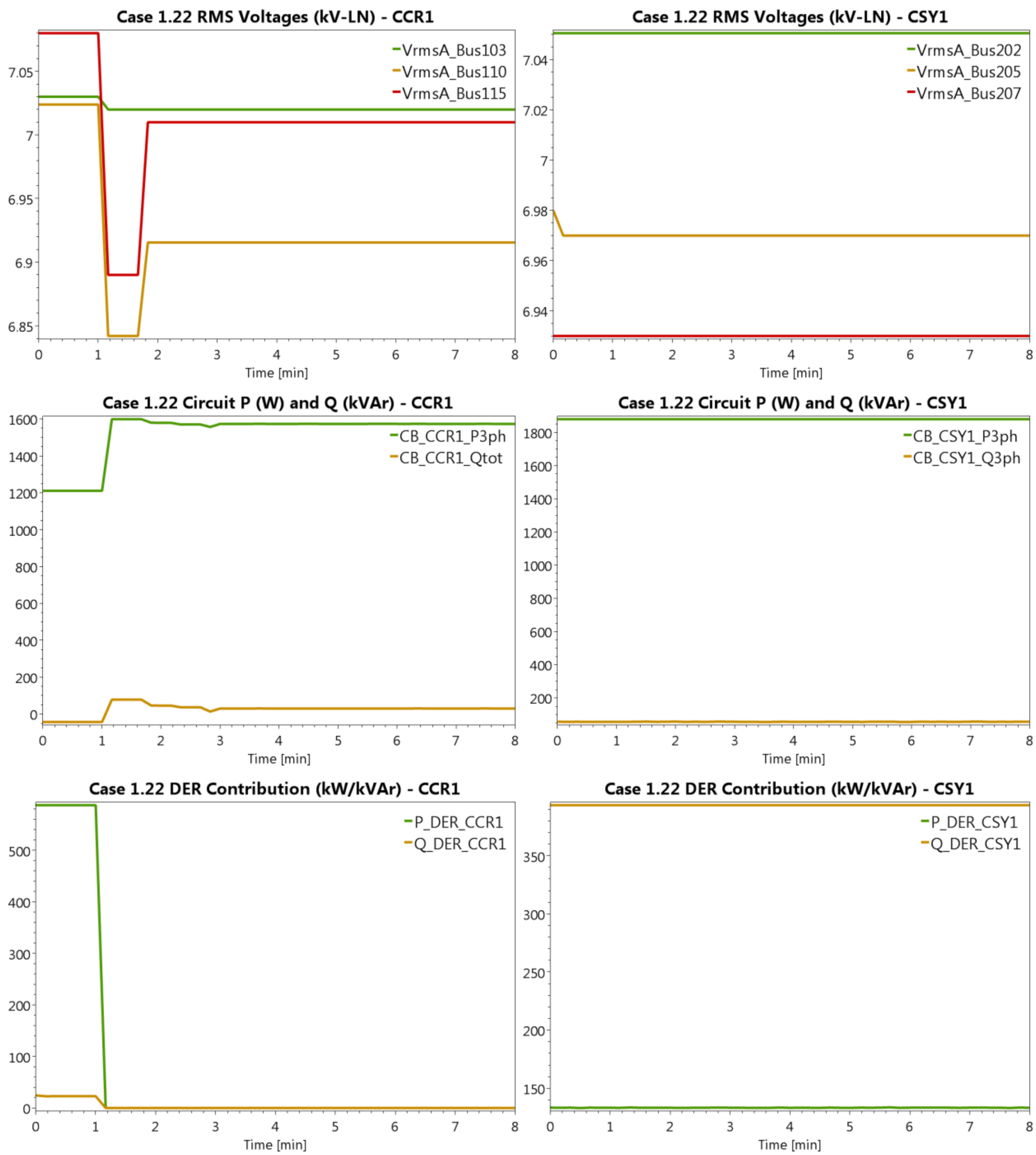

Figure 8-21. Voltage profiles, circuit powers, and DER contributions for Case 1.22

The main feature of the central control (as opposed to local control – Case 1.21) is the improved circuit reactive power regulations.

8.1.18 Test Case 1.23

Table 8.18. Test condition for Case 1.23

Case#	Test Conditions	Remark
1.23	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	Baseline System 2 (all controllable devices were in Local/Auto mode)

Figure 8-22. Voltage profiles, circuit powers, and DER contributions for Case 1.23

In this case that represents a realistic situation, it is observed that the voltage profile of circuit CSY1 is not properly managed and, in some cases, the voltage values are out of range (under CS1).

8.1.19 Test Case 1.24

Table 8.19. Test condition for Case 1.24

Case#	Test Conditions	Remark
1.24	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	Master controller was responsible to take actions through ARC/IVVC algorithm.

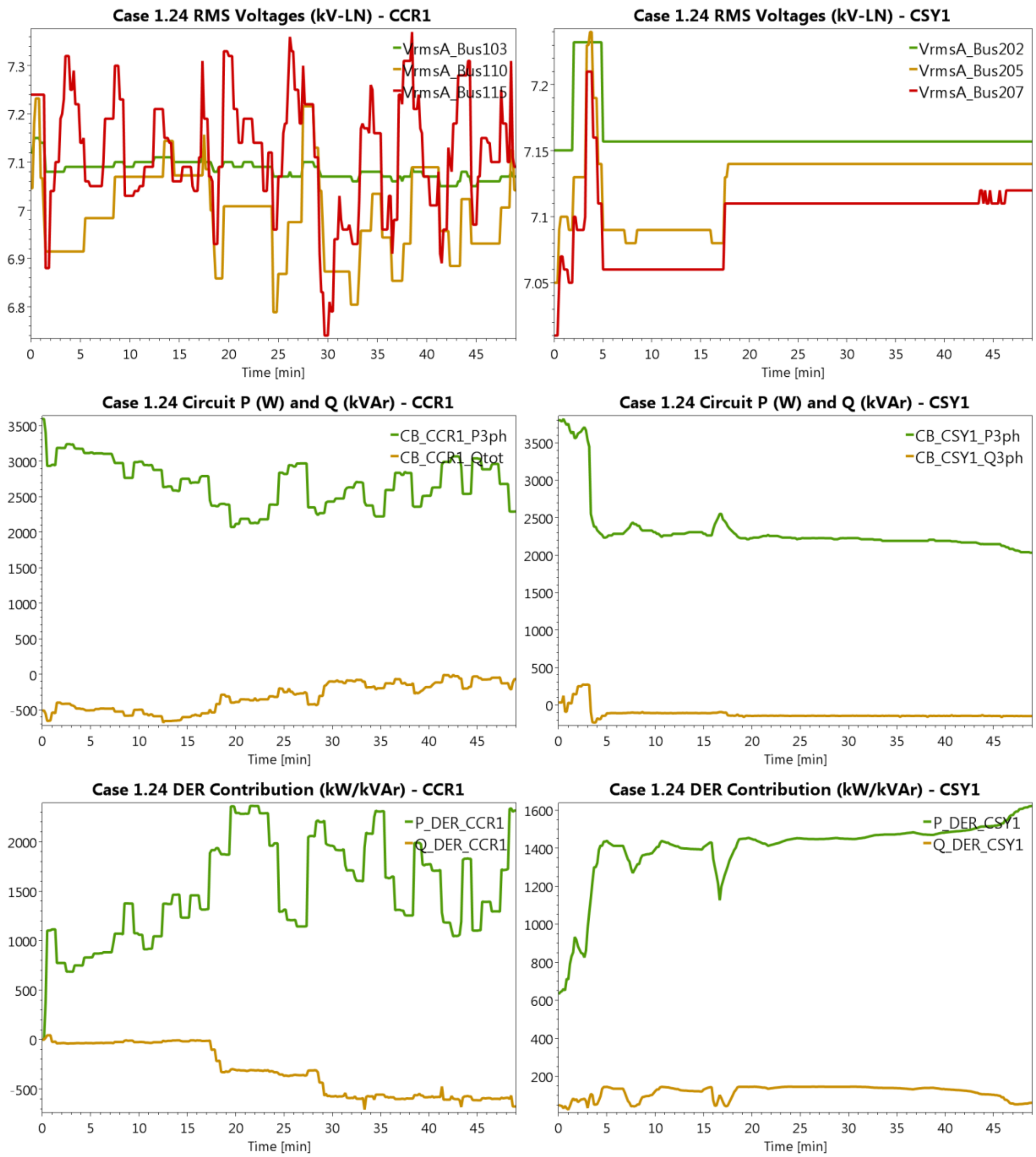

Figure 8-23. Voltage profiles, circuit powers, and DER contributions for Case 1.24

Under CS2, both the voltage profile and the feeder (reactive) power is properly regulated (compare Figure 8-23 with Figure 8-22).

8.1.20 Test Case 1.25

Table 8.20. Test condition for Case 1.25

Case#	Test Conditions	Remark
1.25	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Baseline System 2 (all controllable devices were in Local/Auto mode)

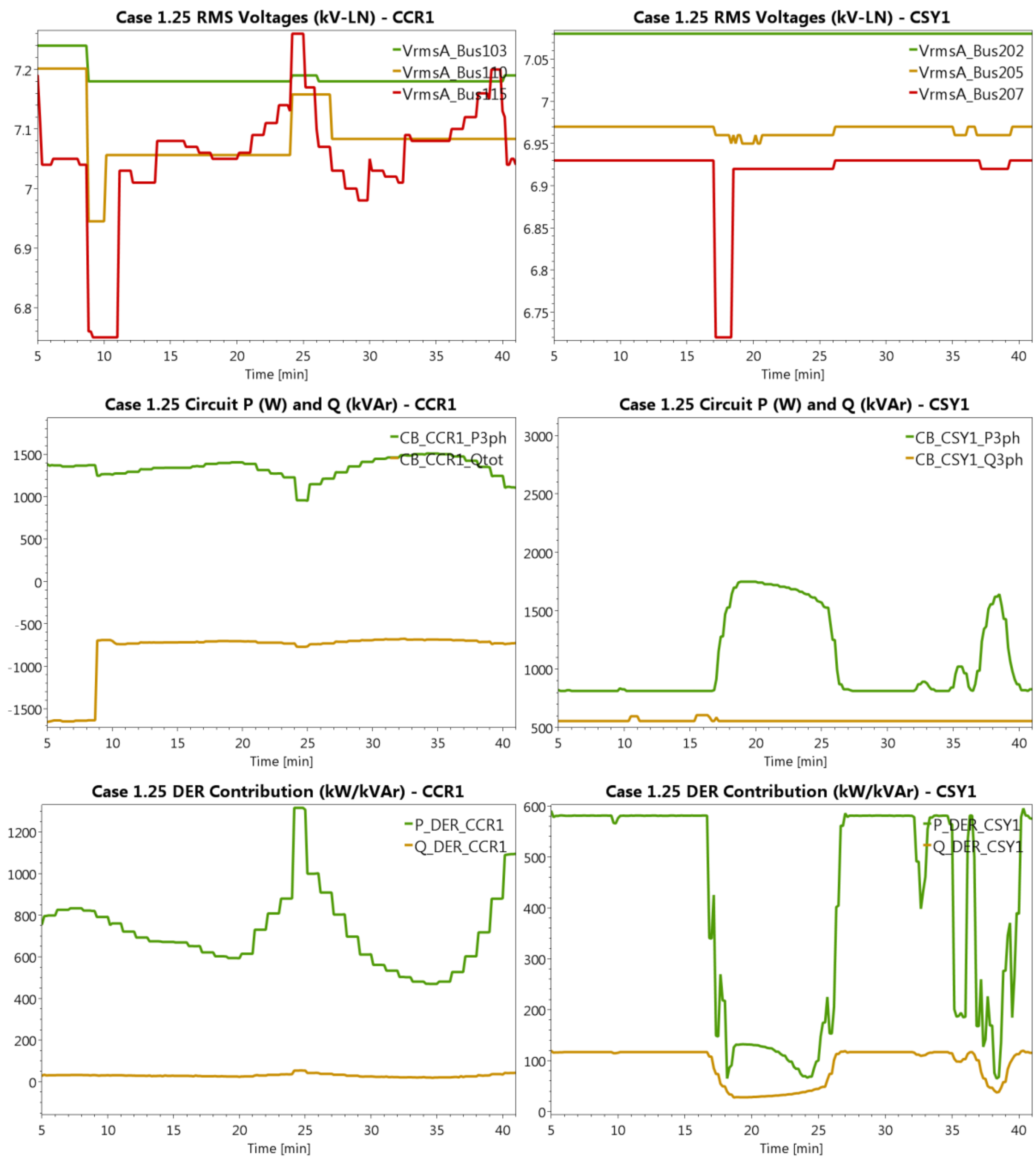

Figure 8-24. Voltage profiles, circuit powers, and DER contributions for Case 1.25

As can be observed in Figure 8-24, Under CS1, the bus voltage occasionally goes out of range. Furthermore, the feeder power is not regulated properly.

8.1.21 Test Case 1.26

Table 8.21. Test condition for Case 1.26

Case#	Test Conditions	Remark
1.26	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Master controller was responsible to take actions through ARC/IVVC algorithm.

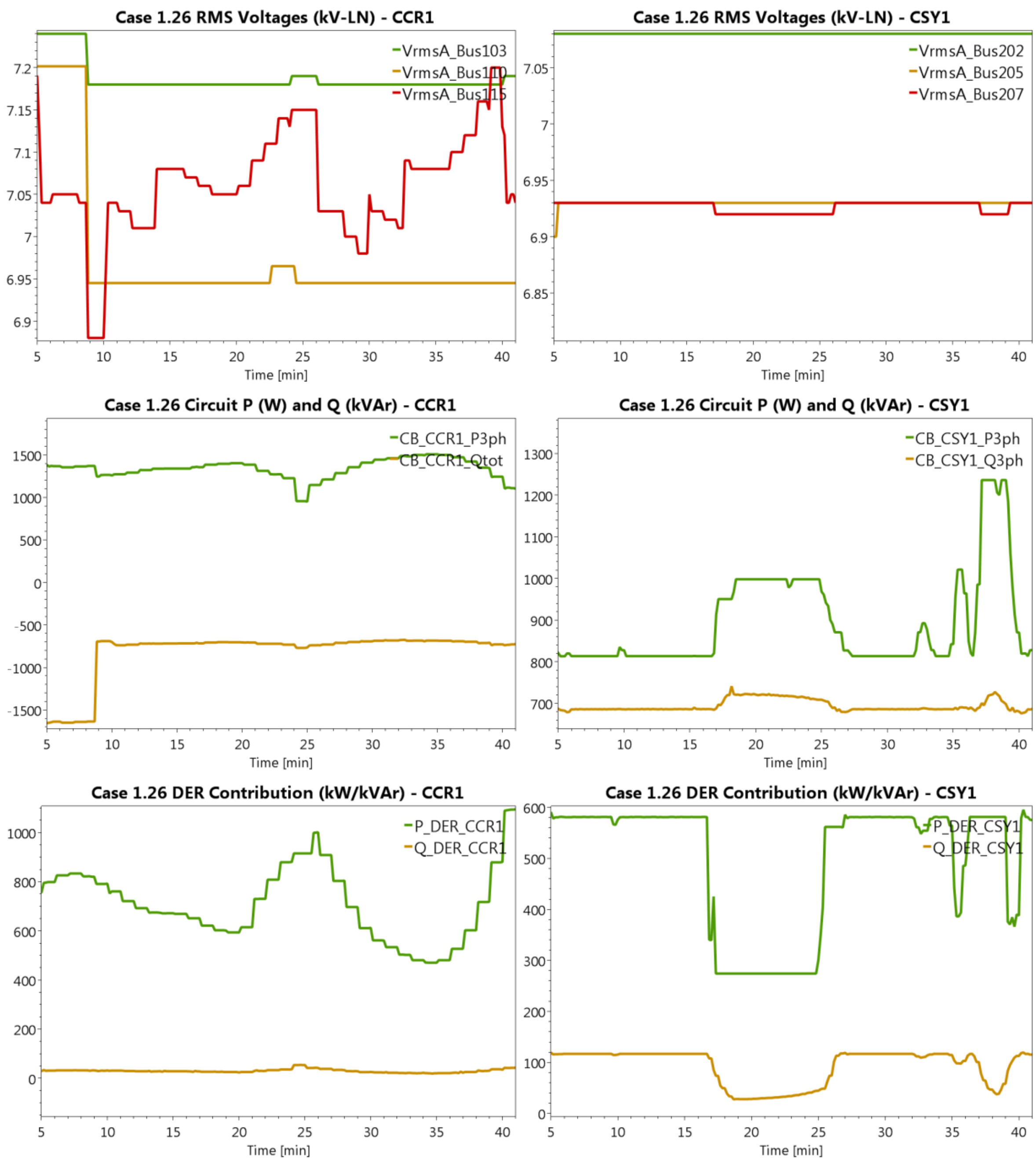

Figure 8-25. Voltage profiles, circuit powers, and DER contributions for Case 1.26

Compared to Case 1.25 (CS1), it is observed in this case (CS2) that the voltage values are always within the acceptable range and circuit powers experience less fluctuations due to the DER involvements.

8.2 Use Case 2: Synchronized Load Transfer

8.2.1 Test Case 2.4

Table 8.22. Test condition for Case 2.4

Case#	Test Condition	Remark
2.4	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

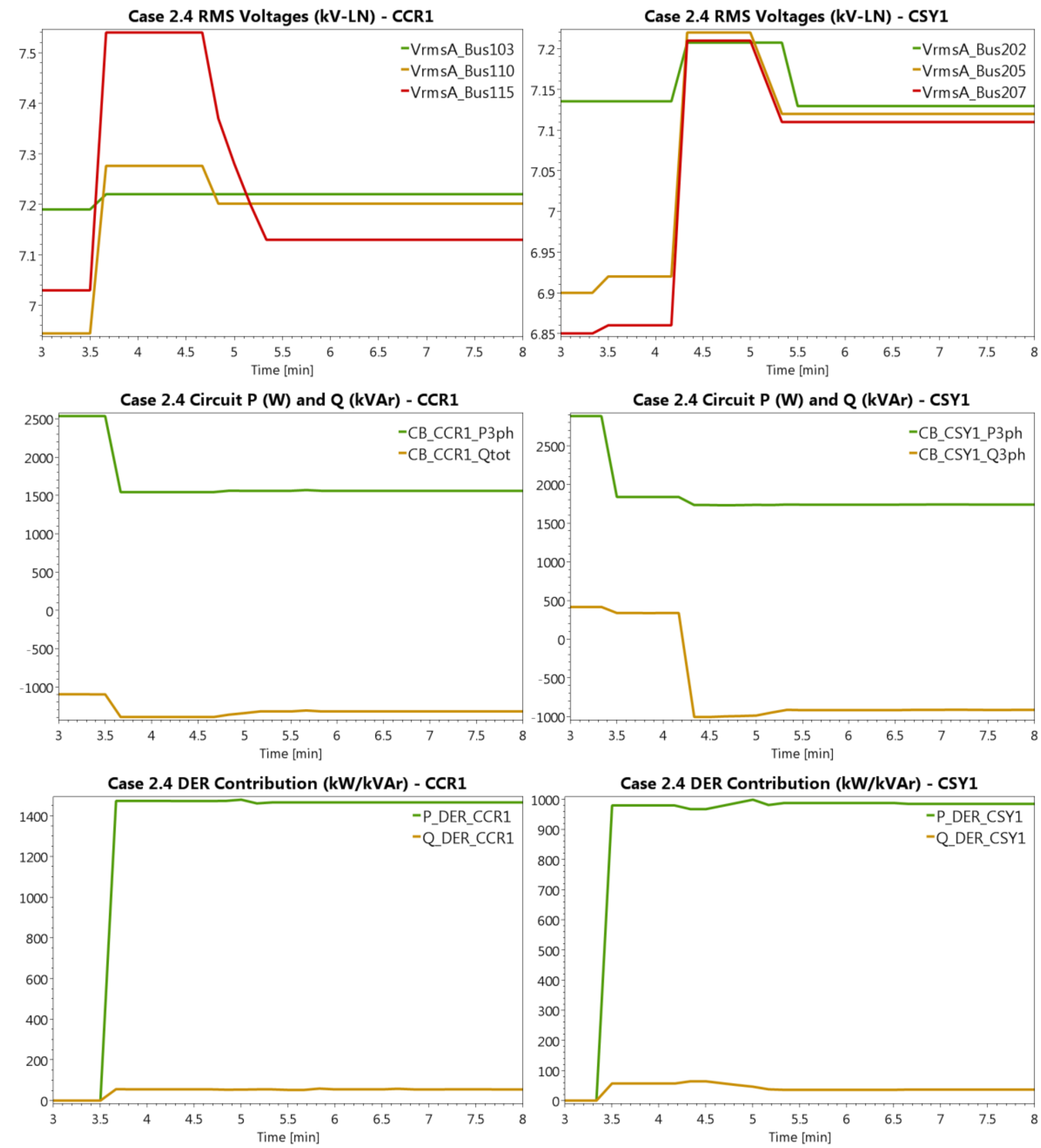

Figure 8-26. Voltage profiles, circuit powers, and DER contributions for Case 2.4

In this case, while there is no reverse real power flowing through feeder breakers, it has taken a relatively long time for local controllers to adjust the bus voltages after the PV profile change.

8.2.2 Test Case 2.5

Table 8.23. Test condition for Case 2.5

Case#	Test Condition	Remark
2.5	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through SLT/IVVC algorithm.

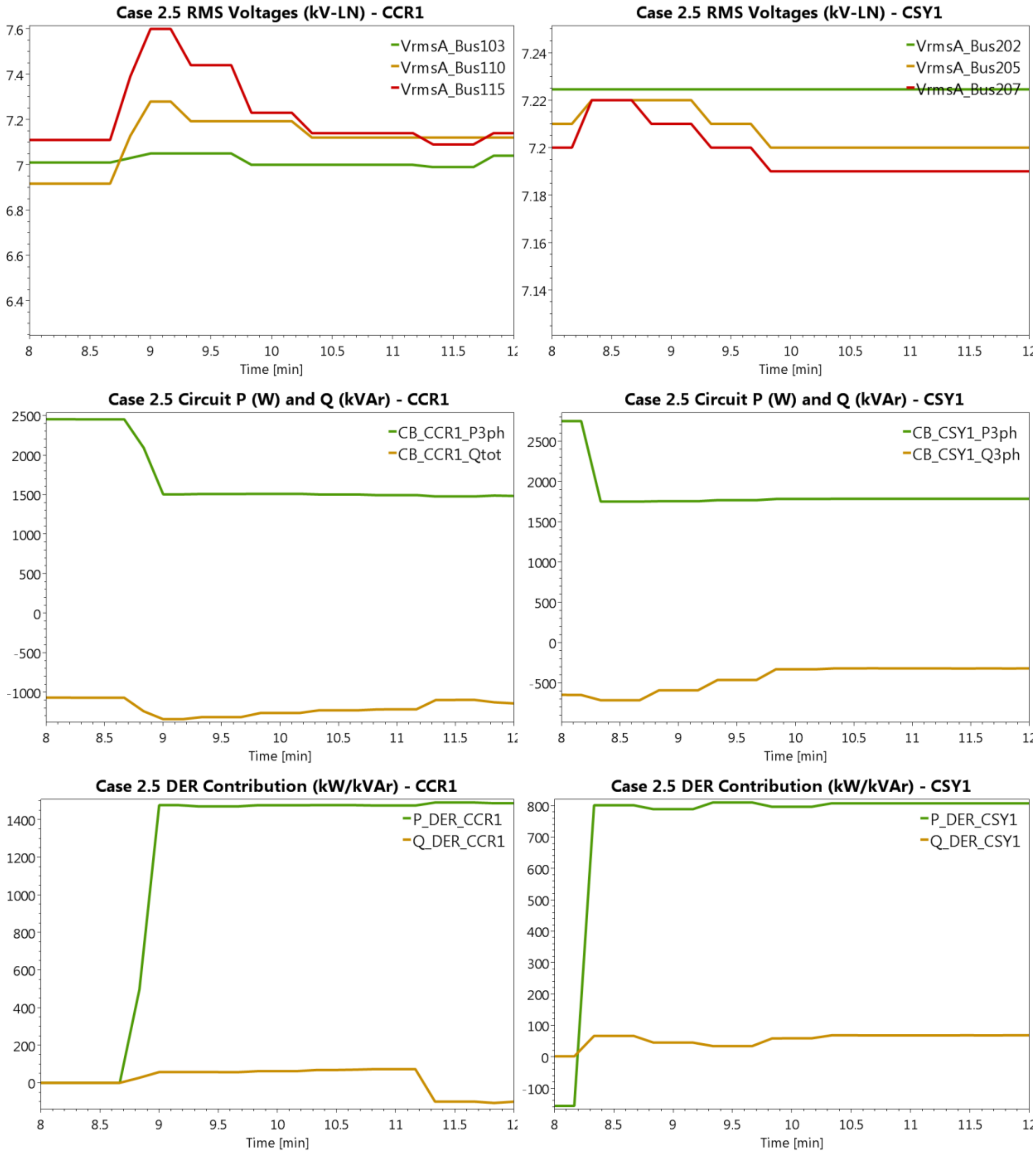

Figure 8-27. Voltage profiles, circuit powers, and DER contributions for Case 2.5

Similar to Case 2.4, no reverse power flow was detected by the SLT engine and, thus, no load transfer was initiated. However, the response times for voltage regulation are faster in this case.

8.2.3 Test Case 2.6

Table 8.24. Test condition for Case 2.6

Case#	Test Condition	Remark
2.6	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission of communication loss (prior to event)

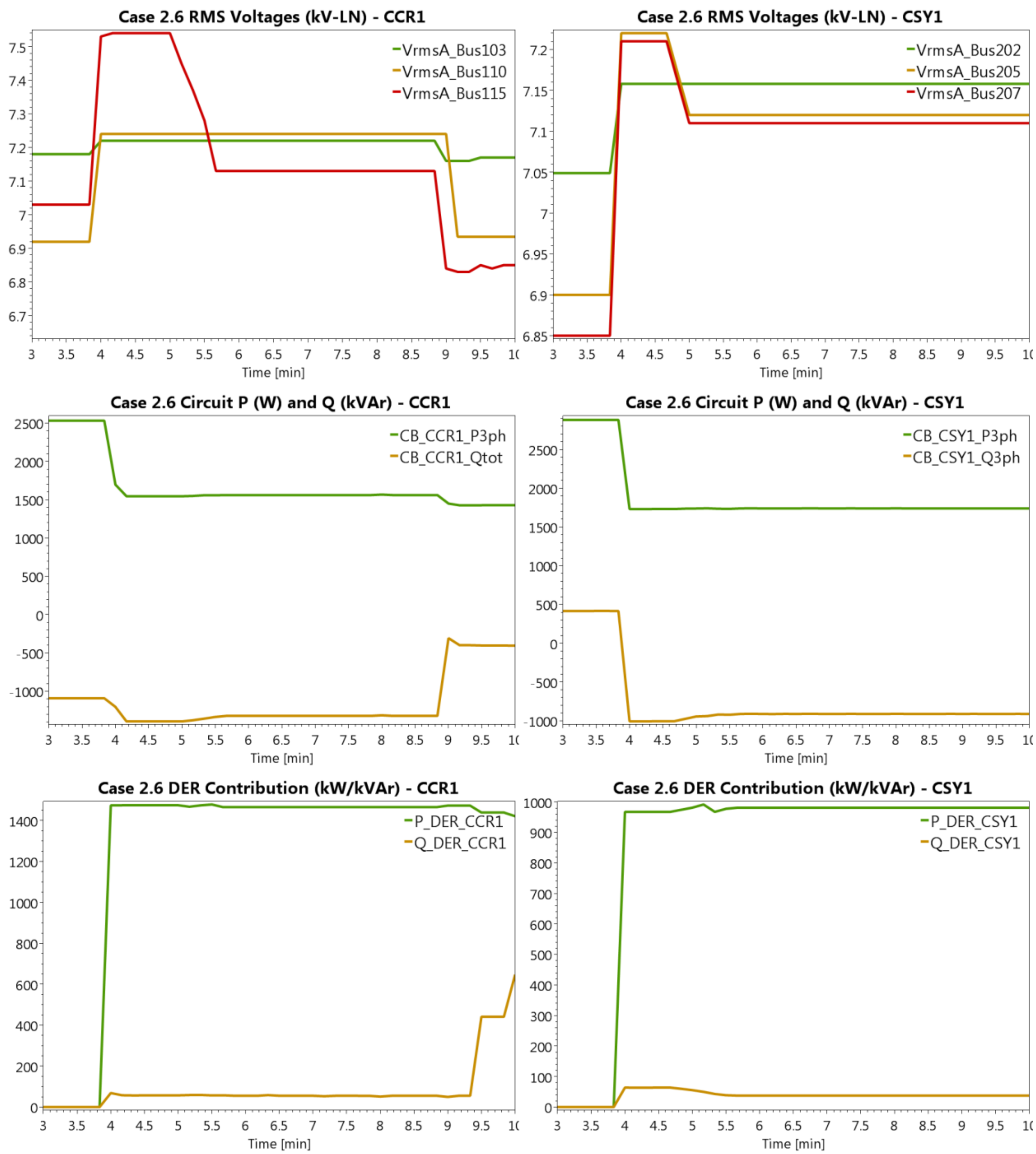

Figure 8-28. Voltage profiles, circuit powers, and DER contributions for Case 2.6

In this case (CS3), the response times are not as good as Case 2.5, but are better than Case 2.4. Additionally, the substation controller uses the substation BESS to improve circuit power factor.

8.2.4 Test Case 2.7

Table 8.25. Test condition for Case 2.7

Case#	Test Condition	Remark
2.7	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

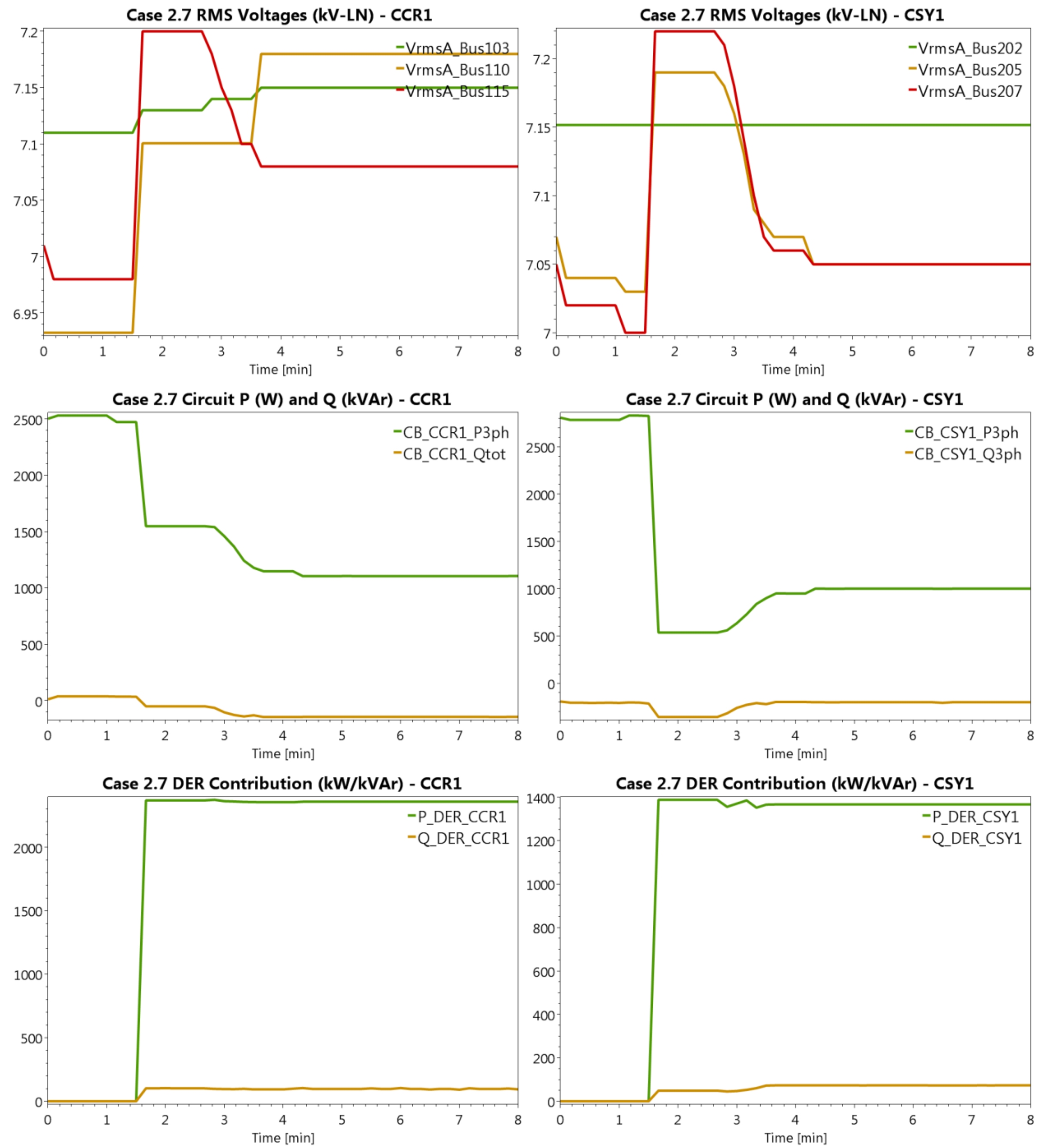

Figure 8-29. Voltage profiles, circuit powers, and DER contributions for Case 2.7

In this case, there is no reverse power issue that requires load transfer. The voltage profiles are also acceptable, but are not optimized (compare with next case, Case 2.8).

8.2.5 Test Case 2.8

Table 8.26. Test condition for Case 2.8

Case#	Test Condition	Remark
2.8	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through SLT/IVVC algorithm.

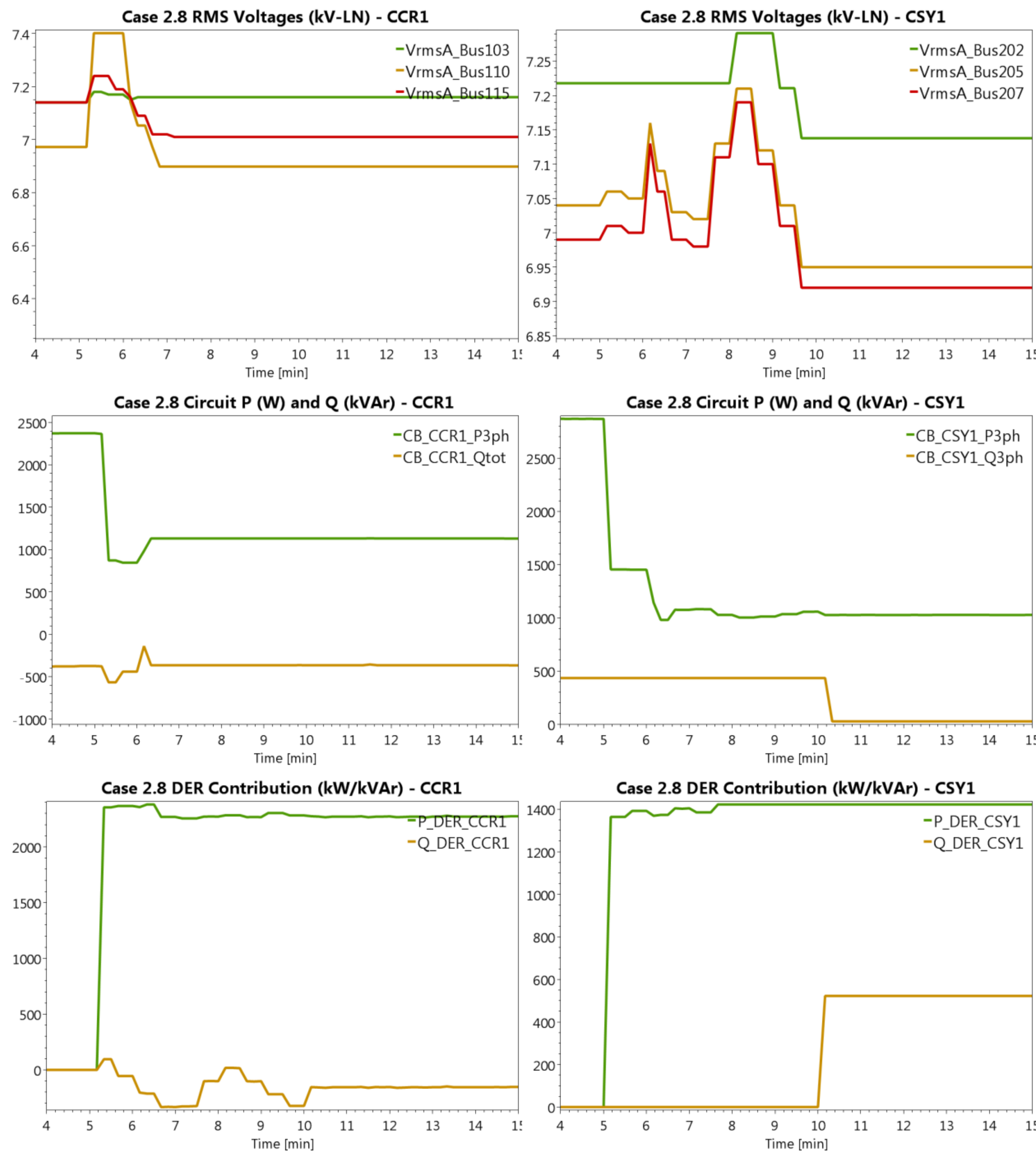

Figure 8-30. Voltage profiles, circuit powers, and DER contributions for Case 2.8

The SLT engine did not detect reverse power flow to initiate a transfer. However, the master controller optimized the voltage profiles as compared to previous case (Compare Figure 8-29 with Figure 8-30)

8.2.6 Test Case 2.9

Table 8.27. Test condition for Case 2.9

Case#	Test Condition	Remark
2.9	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission of communication loss (prior to event)

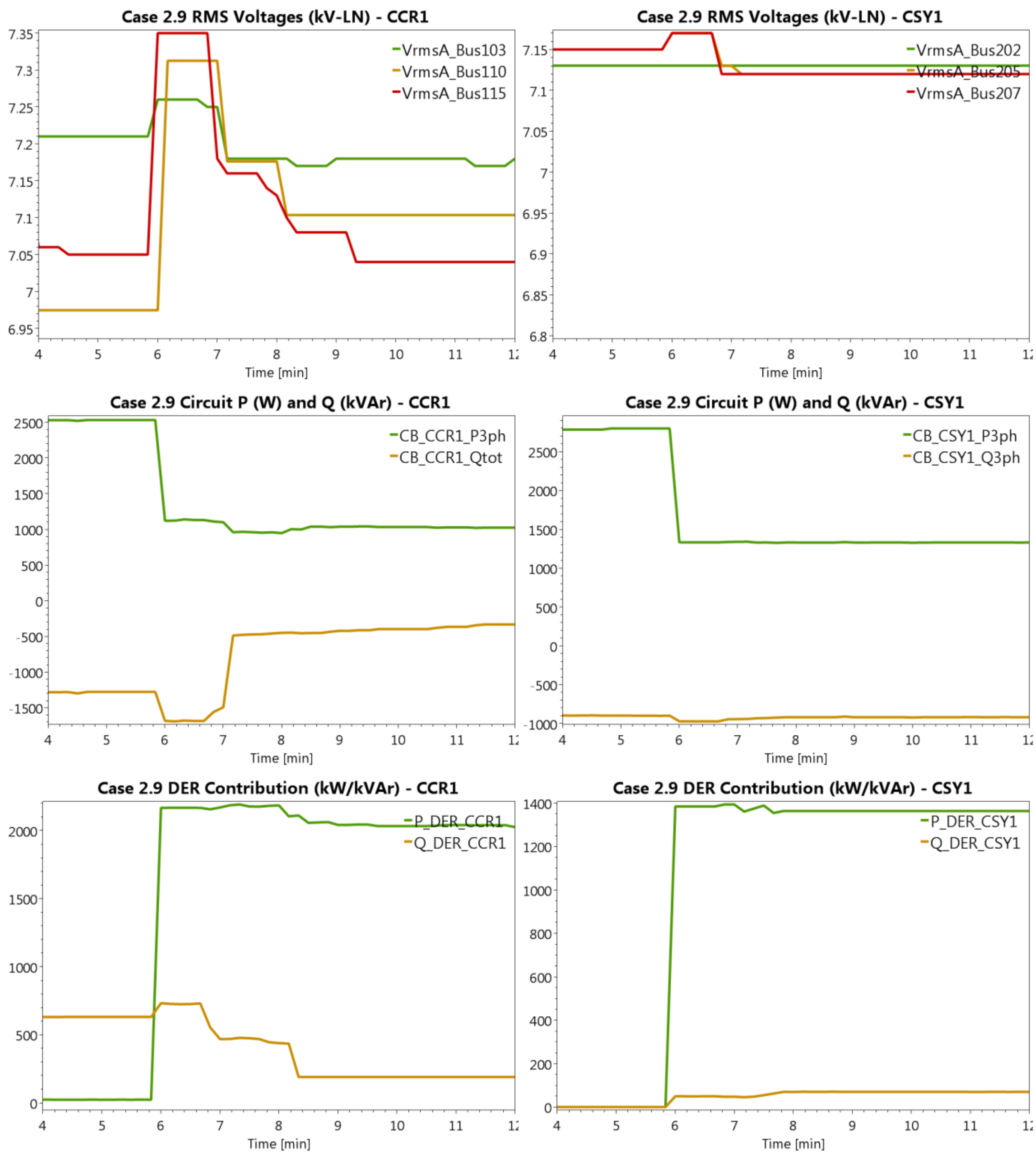

Figure 8-31. Voltage profiles, circuit powers, and DER contributions for Case 2.9

The substation controller cannot regulate the bus voltages as effective as the master controller (Case 2.8), but has the capability to perform the SLT if such a need arises (as opposed to CS1).