Implementing a Microgrid Using Standard Utility Control Equipment

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Implementing a Microgrid Using Standard Utility Control Equipment

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***Abstract*—The Duke Energy McAlpine Creek Substation in Charlotte, North Carolina, has been a test bed for smart grid and renewable generation technology since 2006. The area just outside the substation fence houses a 50 kW photovoltaic installation as well as a 240 kW, 500 kWh battery energy storage system (BESS). These two assets are connected in parallel to import and export energy to a distribution circuit fed from the substation.**

Recent weather events and the drive to develop more renewable generation on the grid have led to extensive efforts in developing microgrids that can provide resiliency for those being served and potentially provide economic benefits for the owner and utility. In 2013, Duke Energy decided to integrate their renewable resources at the McAlpine Creek Substation to provide backup generation services to an adjacent fire station while allowing use of the BESS for grid support services when grid-connected. This effort was completed in 2015. One goal was to develop a model to allow construction and support using standard Duke Energy distribution equipment and off-the-shelf components where possible to allow more integrated support. This paper describes the design, construction, and commissioning of the microgrid controls for the McAlpine Creek microgrid project and lessons learned from its implementation.

I. Introduction

Recent weather events have proven that a single storm can cause billions of dollars of damage to the electrical power grid as well as significant power outage-related costs [1] [2]. As a result, utilities across the United States are working to make their services more resilient. This alone is a challenge, but some utilities also face state-level pressure to improve the reliability of their systems. In 2014, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS), driving utilities in that state to add more renewable resources to their systems [3]. This resulted in North Carolina ranking fourth in the United States in total installed solar capacity with 397 MW of solar installations and with the second-fastest growth of solar capacity nationwide [4] [5]. The economic impact of weather events and this drive to add renewable resources led the North Carolina utility Duke Energy to develop its own solar-powered microgrid demonstration project.

Since 2006, the Duke Energy McAlpine Creek Substation in Charlotte, North Carolina has been a test bed for smart grid and renewable generation technology. The area just outside the substation fence houses a 50 kW photovoltaic (PV) installation as well as a 240 kW, 500 kWh battery energy storage system (BESS). These two assets are connected in parallel to import and export energy to McAlpine Creek Circuit 2414 at the substation.

Located adjacent to the substation property is the City of Charlotte Fire Station 24 (FS24). Duke Energy and the City of Charlotte agreed to partner in a mutually beneficial technology proof-of-concept project. FS24 was interested in having the PV installation and the BESS combined to provide backup generation services to the fire station. Duke Energy was interested in using the BESS for grid support services when it was grid-connected.

The Duke Energy Emerging Technology Office seeks projects that align with and support Duke Energy's strategic objectives. This team determined that a vertically integrated microgrid (a business model where the utility owns the distribution infrastructure and generation and storage assets, operates the microgrid as a small grid, and sells the power to customers [6]) using standard switching and control components would provide the most relevant learning opportunities for Duke Energy. If desired, this design could also potentially fit within a future regulated microgrid customer offering.

The following project goals and objectives were identified by the Duke Energy Emerging Technology Office team when embarking on the McAlpine Creek microgrid project.

A. Provide Resiliency to a Critical Facility

FS24 serves as the critical load. It already had an onsite, backup diesel generator and radio, making it immune to the risks associated with a demonstration project such as this. However, the project was to prove that FS24, when fed from the microgrid, would be able to operate during periods of prolonged grid outages with seamless disconnection and reconnection of the microgrid to the power grid.

B. Use Utility-Owned, Utility-Sited Assets

Duke Energy owns, operates, and maintains all the equipment used in this project along with all the existing microgrid equipment located on the distribution circuit.

C. Develop a Model to Allow Construction and Support Using Duke Energy Distribution Standards

Several microgrid demonstration projects have used specialized disconnection means and controllers. It was Duke Energy's goal to use off-the-shelf components for these functions to allow for more integrated support from the distribution organization.

D. *Demonstrate Ancillary and Grid Stability Services*

Besides serving a critical load, Duke Energy wanted to demonstrate that the utility-owned microgrid could provide other benefits to their distribution system as well, including the following:

- Frequency regulation.
- Circuit voltage support (VAR dispatch).
- Demand response through islanding.
- Mitigation of solar intermittency at the source.

II. Feasibility Study Stage

The initial investigation into inverter-based generation systems revealed multiple technical challenges to overcome. The challenges included the following:

- Integrating PV and BESS assets that were not designed to perform in unison.
- Understanding how the PV installation and BESS could allow for off-grid operation.
- Dealing with the reduction in fault current when feeding the microgrid from the inverters.
- Developing new protection and control schemes to allow seamless islanding and resynchronization to the grid.
- Testing power limits to understand how BESS operation may affect islanding performance.

Besides identifying these engineering challenges, three tasks were undertaken to help determine the feasibility of combining the PV and BESS equipment into a working microgrid—an investigation of operating and control modes, a fault protection study, and a load profile analysis.

A. *Investigation of Operating and Control Modes*

The following definition of a microgrid has achieved broad acceptance: "A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode" [7] [8]. The Duke Energy team set out to verify whether the existing equipment at the McAlpine Creek Substation would support operation in both grid-connected and island modes and meet the requirements of a microgrid.

When islanded, the PV installation and BESS must act as a generation source and feed 480 V, 60 Hz power to FS24. An initial investigation into the operating modes of the BESS determined that the BESS inverter would only operate in current source (Sc), or grid-connected, mode. Voltage source (Sv) operation of the BESS is required for islanding as a microgrid. Duke Energy contracted with the BESS provider to upgrade the BESS inverter firmware in order to provide Sv mode operation.

When the microgrid is connected to the distribution grid, the PV installation and BESS use Sc mode. The output current of the BESS or PV installation is regulated, and the output voltage matches the voltage of the grid. In Sv mode, the BESS regulates the output voltage and frequency to 480 V, 60 Hz and modulates the current to match the load, which in this case was FS24.

After upgrading the BESS firmware, the Duke Energy project team designed a series of tests using a load bank. This simulated the FS24 load and sought to determine whether the PV installation and BESS could transition from grid-connected to island mode and then ultimately support FS24 while in island mode.

Testing took place over several months and resulted in the following five key findings:

1. The BESS operation would allow support of the microgrid in Sv mode.
2. Switching from grid-connected to island mode could take place with both the PV installation and the BESS online and operational at various power levels.
3. The transition from grid-connected to island mode takes 5 to 6 cycles for the BESS to complete (shown in Fig. 1).
4. In several scenarios, low output levels from the PV inverter could create a "noisy" condition when islanding and therefore trip the inverters.
5. BESS power levels (discharging and charging) above 125 kW could present a condition where the inverters trip offline when islanded.

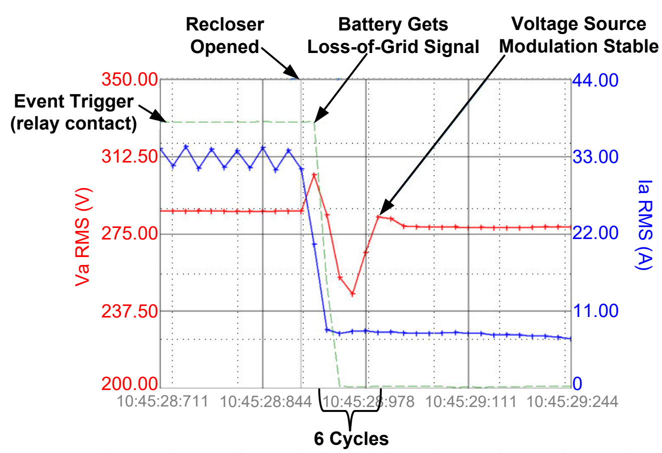


Fig. 1. Waveform of Transition From Grid-Connected to Island Mode

B. *Fault Protection Study*

After the project team consolidated the test data, a fault protection study of the proposed microgrid circuit began. The fault protection study identified that the PV and BESS inverters did not provide sufficient fault current to trip the FS24 panelboard circuit breakers during island mode operation. The team identified a solution: changing the main breaker in FS24 to an electronic breaker with adjustable trip points. This change provided suitable protection when the microgrid was islanded. The microgrid design incorporated a new breaker that replaced the existing FS24 main breaker.

C. *Load Profile Analysis*

As part of the feasibility study, the team conducted a load profile analysis (shown in Fig. 2) to determine the length of time the microgrid could support FS24. For a period of 7 days, the team collected 5-minute meter data for the solar energy and FS24 load. With a nominal 15 to 20 kW load from FS24, it was determined that the microgrid could support the load for approximately 36 to 48 hours, depending on the time of the islanding event and how much solar energy would be available during the microgrid operation.

A survey of the loads in FS24 revealed that no loads would present a challenge for the inverters to overcome inrush current. Thus, the starting and stopping of air conditioning and the opening and closing of garage doors would not present an issue.

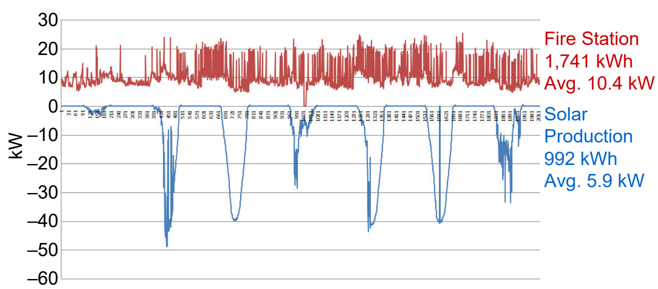


Fig. 2. Seven-Day Load Profile of FS24 and Solar Production

III. Design Stage

The installation of the PV array and the BESS occurred under separate projects and at different times. Accordingly, no communications or control systems existed to facilitate data transfer to a microgrid controller providing coordinated operation of the assets. The design stage included the design and selection of the major components necessary for microgrid operation as shown in the one-line diagram in Fig. 3.

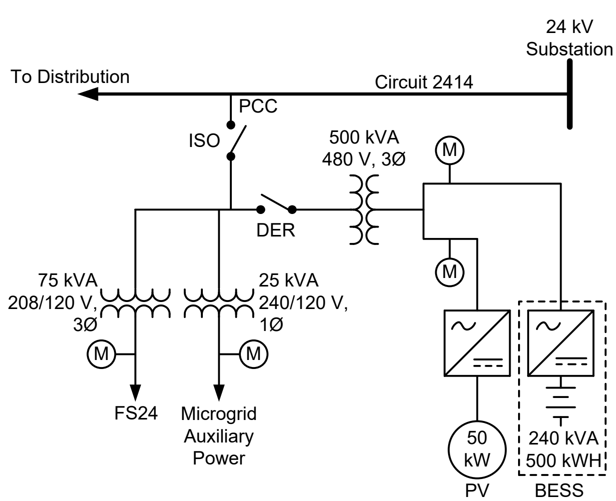


Fig. 3. Microgrid One-Line Diagram

An existing recloser control was applied as a distributed energy resource (DER) switch; this switch was used to tie the PV installation and the BESS to the local load. A new recloser was added that acted as a microgrid isolation (ISO) switch; this switch was used to tie the microgrid to the distribution system at the point of common coupling (PCC). Other major components that were added included a new microgrid controller, auxiliary power, and the communications wiring and equipment necessary for the microgrid controls and communications to Duke Energy's distribution supervisory control and data acquisition (SCADA) system.

A. *Microgrid Controller*

A microgrid controller was specified to consolidate all the monitoring, control, and communications of the microgrid. It was selected based on the following attributes.

1) *Communications*

To allow data collection from all devices, Duke Energy required the microgrid controller to have both Ethernet and serial communications interfaces that supported both Distributed Network Protocol (DNP3) and Modbus® client protocol for polling the devices at the site.

2) *Protocol Conversion and SCADA*

In order to present the overall status of the McAlpine Creek microgrid to SCADA operators for monitoring and control, the microgrid controller needed to support protocol conversion into DNP3 for the server connection to SCADA.

3) *Physical I/O*

Integrated, hard-wired contact inputs and outputs were necessary to support the design and needed to be rated to accept 120 Vac and 125 Vdc to match the whetting voltage available at the site. The input and output contacts were to be used to transfer the status of the ISO and DER switches to the BESS.

4) *Logic Engine*

The microgrid controller was designed to play an integral role in islanding and resynchronization routines, as well as handle multiple, different operating scenarios based on solar energy output, battery status, and grid status. Duke Energy specified that the logic engine should be fully customizable and should adhere to industry standards.

5) *Human-Machine Interface (HMI)*

The microgrid controller needed to support an HMI that would allow local or remote monitoring and supervision.

Based on these specifications, Duke Energy selected an off-the-shelf automation controller platform that would be a standard item in their inventory for future service, replacement, and warranty purposes.

B. *Reclosers*

Duke Energy's standard triple-single recloser and control devices were used for both the ISO and DER switches. Each switch is operated as a three-phase recloser with the reclosing functionality disabled.

1) *ISO Switch Protection and Controls*

Duke Energy uses a standard settings template for its recloser controls. This template had to be modified in order to support microgrid operation for the ISO switch. The first primary modification was to separate the microgrid from the system on undervoltage when it is in automatic mode and to quickly alert the BESS to go into Sv mode. This has to occur prior to the BESS shutting down due to undervoltage. The BESS shuts down for a voltage below 85 percent for

2 seconds or a voltage below 50 percent for 200 milliseconds. In order to coordinate with this, the ISO switch was programmed to open for a voltage below 90 percent for 1.5 seconds or a voltage below 55 percent for 100 milliseconds.

The second primary modification was the addition of a synchronism check to allow the microgrid to synchronize back to the system. A synchronizing algorithm was applied in the microgrid controller to accomplish this (described in Section IV).

Duke Energy's standard recloser control offered both proprietary and DNP3 communications over Ethernet, but it did not include optional IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging. Therefore, a separate MIRRORED BITS® communications channel was used where high-speed communication of the ISO status was required. This communications channel used fiber-optic cable between the ISO switch and a remote I/O module in the control house that provided the ISO status to the BESS. This remote I/O module was also standard equipment used by Duke Energy.

2) DER Switch Protection and Controls

As with the ISO switch, Duke Energy's standard recloser control settings template had to be modified for the DER switch. Because little fault current is available from the BESS, the protection in the DER switch relies on undervoltage elements to detect a fault when the microgrid is operating in Sv mode. Separate undervoltage elements were applied for grid-connected and island modes, and the elements were set at 80 percent and 70 percent pickup, respectively. Underfrequency and overvoltage protection were also added to the normal overcurrent elements used for tripping. Additionally, when the microgrid controller communicates to the DER switch that the microgrid is in manual mode (described in Section IV, Subsection A), the logic in the DER switch closes the switch whenever the source voltage returns and the BESS voltage is dead.

C. Auxiliary Power

An existing 24 kV/240/120 V auxiliary transformer was on McAlpine Circuit 2415. As part of the construction build out, the transformer was moved to McAlpine Circuit 2414 to facilitate true self-contained microgrid operation.

An evaluation of the auxiliary power needs for the microgrid showed that the load to operate the electronic controls equipment, air conditioning and heating, communications equipment, and inverter controls could be as high as 12 kW. In addition, it was determined that the BESS inverter controls would signal an auxiliary power loss if the voltage dropped below 186 V (nominal 240 V). The BESS inverter would then shut down and open its contactors, rendering the BESS and the microgrid inoperative. It is important to ensure that the voltage stays above 186 V for the few cycles during the transition from grid-connected to island mode. Accordingly, a 10 kVA constant voltage transformer (CVT) was installed on the BESS auxiliary power circuit.

IV. MICROGRID CONTROLLER PROGRAMMING AND OPERATIONS

Leading up to the programming of the microgrid controller, Duke Energy developed a set of control modes and scenarios of operation that defined the inputs, outputs, and variables needed to execute the microgrid design.

A. Microgrid Control Modes

Duke Energy developed the following three control modes:

- Mode 1—automatic mode with manual resynchronization.
- Mode 2—automatic mode with automatic resynchronization.
- Mode 3—manual mode.

Mode 1 is generally used for demonstration purposes and testing. In this mode, the microgrid automatically responds to a grid outage by islanding, or it allows an operator to manually island the microgrid by issuing an open command to the ISO switch. The microgrid then remains in island mode, supporting the FS24 and auxiliary loads with the PV installation and BESS resources, until a manual resynchronization command is issued by an operator.

Mode 2 was defined for the long-term operation of the microgrid. Similar to Mode 1, the microgrid automatically responds to a grid outage by islanding. Mode 2 differs in that the resynchronization routine occurs automatically after a specified delay period when the grid has been restored, as sensed by the recloser controller at the ISO switch. This allows the microgrid to autonomously support the islanded loads during grid outages and then automatically resynchronize and resume grid connection upon restoration of normal grid voltage and frequency.

Mode 3 is used to recover from abnormal conditions or situations, or for testing purposes. There is no automatic islanding or resynchronization; all operation follows manual controls from the SCADA system or the local HMI operator.

Switching to Mode 1 or Mode 2 is only allowed under the following conditions:

- The DER switch is closed.
- The grid circuit is energized at the PCC.
- The BESS inverter is in either "standby" or "running" work state.

B. Operating Scenarios

In the course of planning and testing the microgrid system, the following four scenarios were examined:

- Grid outage.
- Automatic resynchronization.
- Manual resynchronization.
- Manual islanding.

In the following subsections, the applicable modes for the scenarios are listed, followed by the course of events for each scenario.

1) Grid Outage (Modes 1 and 2)

When the grid circuit becomes de-energized, the ISO switch senses the voltage drop and opens the switch. The open switch contact status is transmitted to the BESS inverter to put it into voltage source (Sv) mode. At this point, the microgrid is islanded, and the BESS inverter's output maintains the microgrid voltage and frequency at user-specified set points. User-settable battery state-of-charge (SOC) limits are in effect when the BESS inverter switches to Sv mode. When the BESS reaches a high SOC percentage, the microgrid controller trips the PV installation offline to prevent overvoltage to the battery, and when it reaches a low SOC percentage, the microgrid controller sends a command to the BESS inverter to enter an idle work state, de-energizing the microgrid. FS24 would rely on its diesel generator in the event of the loss of both grid voltage and microgrid voltage.

2) Automatic Resynchronization (Mode 2)

Upon restoration of grid voltage, Mode 2 enables the microgrid controller to automatically issue the initiate synchronization routine command if all conditions for resynchronization are met (see Subsection C, Synchronization Routine).

Successful resynchronization occurs when the ISO switch completes a synchronism check and closes, and subsequently the contact signal de-asserts at the BESS inverter. At that point, the BESS inverter returns to Sc mode, and the microgrid load shifts back the grid.

3) Manual Resynchronization (Modes 1 and 3)

During an islanded condition in Modes 1 and 3, SCADA or local HMI operators are able to manually issue an initiate synchronization routine command from the microgrid controller. The process then continues as described previously in Subsection 2, Automatic Resynchronization.

4) Manual Islanding (Modes 1, 2, and 3)

While tied to the grid in Mode 1, SCADA or local HMI operators can issue the island command from the microgrid controller to the ISO switch. After manually islanding, the process then continues as described previously in Subsection 1, Grid Outage.

C. Synchronization Routine

A customized synchronization routine was developed in the microgrid controller logic environment in order to bring about the conditions in which the ISO switch completes its synchronism check and resynchronizes the microgrid to the grid. As mentioned previously, the initiate synchronization routine command may be issued automatically or manually, depending on the control mode in effect as well as the condition of microgrid voltage and grid voltage. To detect the health of both the microgrid and the grid, the conditions "Grid Healthy" and "Microgrid Dead" are sensed via voltage inputs on the ISO and DER recloser controllers and then passed to the microgrid controller, which executes the logic structure shown in Fig. 4 using comparison operators and a timer.

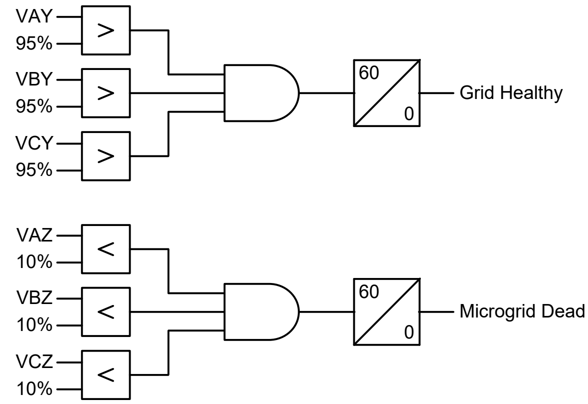


Fig. 4. Grid and Microgrid Voltage Detection Logic

Based on the conditions tested in Fig. 4, the algorithm in Fig. 5 indicates both the automatic and manual conditions in which the microgrid controller enters into the synchronization routine.

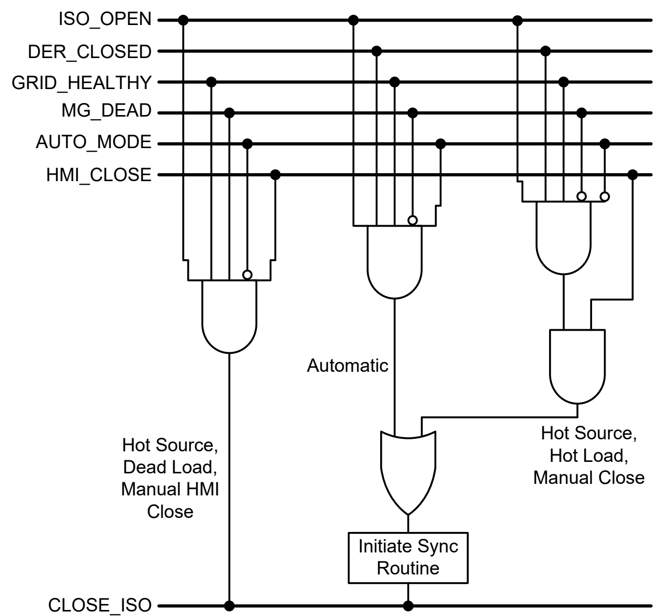


Fig. 5. Initiate Synchronization Routine Logic Algorithm

Once initiated, the microgrid controller synchronization routine first calculates the average of the three-phase voltage measured on the grid by the ISO switch. It then converts that value to a voltage set point of the low side of the DER transformer and writes that voltage as a Modbus analog set point to the BESS inverter, which is in Sv operating mode during the islanded condition. The microgrid controller then begins to issue a declining frequency ramp as a set point to the BESS inverter, setting up a condition where the BESS inverter's phasors are moving slightly faster than the grid initially but gradually approaching grid frequency every processing interval. In addition, a synchronism-check permissive is sent to the ISO switch, indicating it should re-close upon completing its voltage and frequency synchronization checks. Once the synchronization routine has begun in the microgrid controller, the ISO recloser then makes the ultimate decision to close and synchronize the two circuits. If, for some reason, the output frequency ramp completes without a successful synchronization, the routine is interrupted and it waits for a new initiation command, issued either automatically or manually. The logical flow chart in Fig. 6 was used to program the microgrid controller to execute this logic.

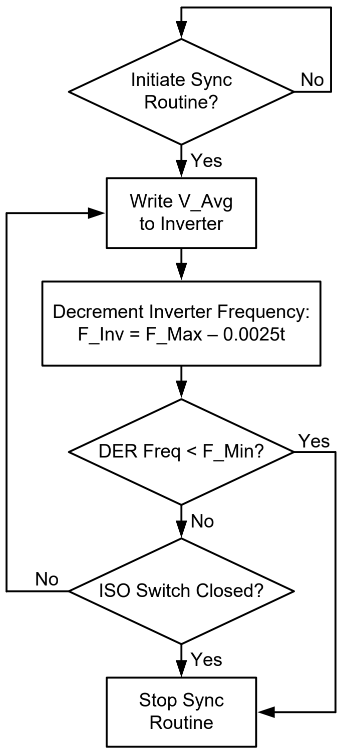


Fig. 6. Synchronization Routine Logical Diagram

Any changes in grid voltage during the synchronization routine are accounted for by checking and writing the average voltage to the BESS inverter each processing interval until either the ISO switch closes or the routine is interrupted.

D. HMI

For the real-time monitoring and control of all microgrid assets, the HMI feature of the microgrid controller was programmed with the detail screens shown in Fig. 7 through Fig. 12, allowing local and SCADA operators the ability to change modes, issue islanding and synchronization commands, send controls and set points to the BESS inverter, and view or acknowledge alarms on the system.

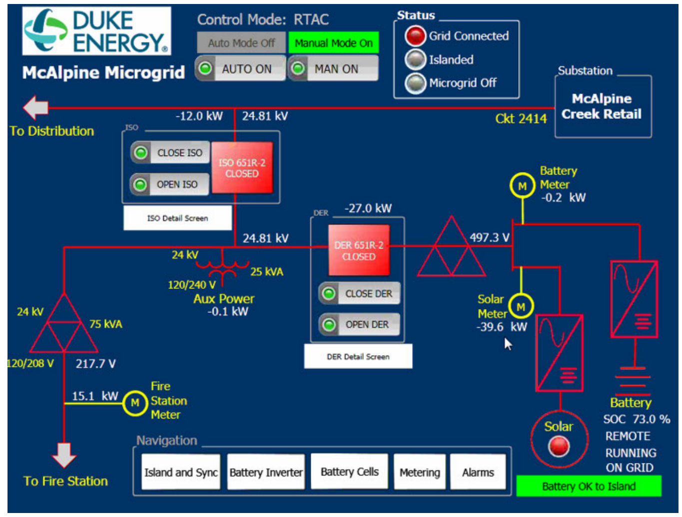


Fig. 7. HMI Overview Screen

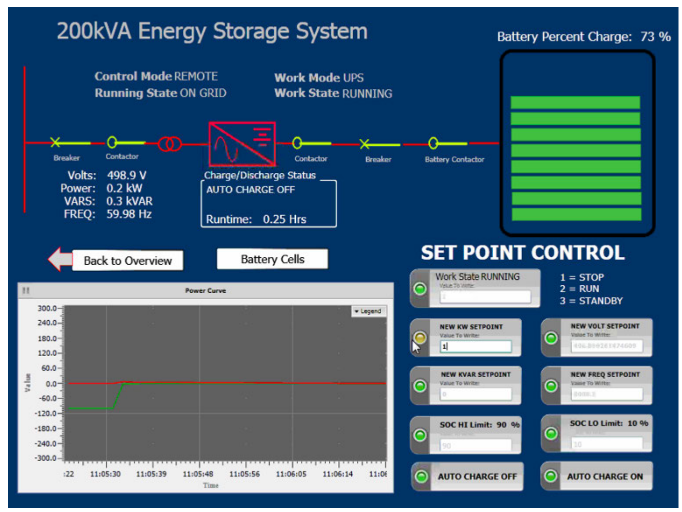


Fig. 8. Battery Monitoring Detail Screen

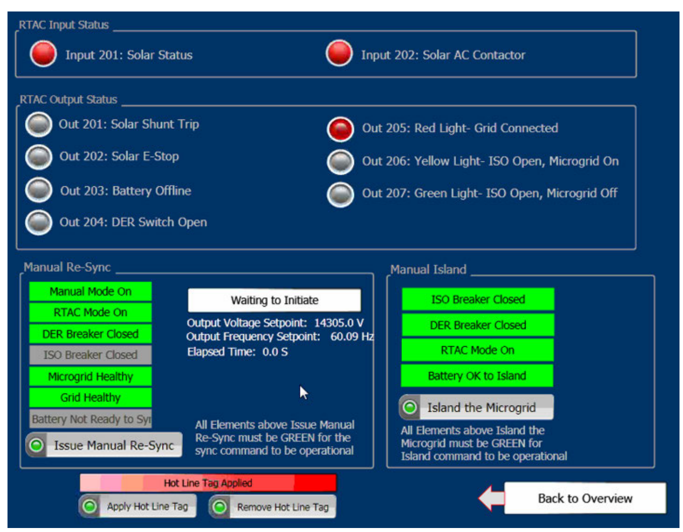


Fig. 9. Islanding, Resynchronization, and I/O Detail Screen

Fig. 10. ISO Switch Detail Screen

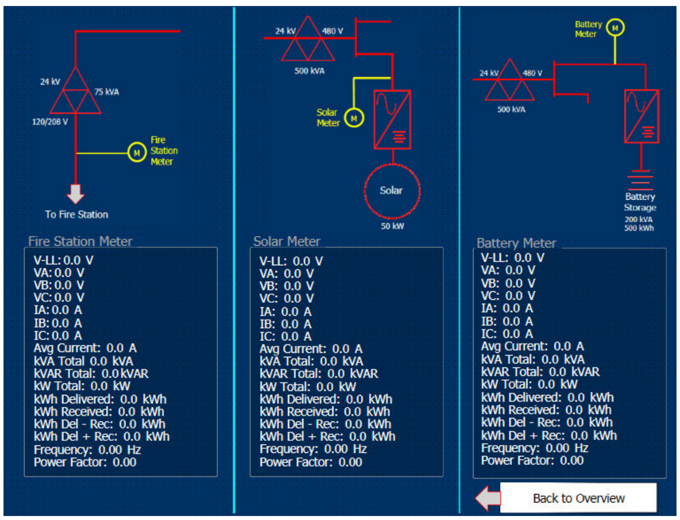


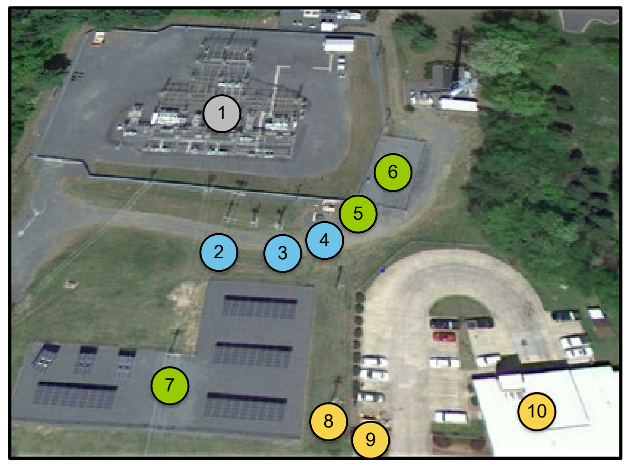
Fig. 11. Metering Detail Screen

Fig. 12. Alarm Detail Screen

V. Construction

Duke Energy's internal organizations assembled the microgrid components that are native to the core business of the utility. Distribution Engineering designed the required circuit modifications and created drawings for the construction of the microgrid circuit. Power Delivery built out the microgrid circuit and provided the service changeover to FS24. Protection and Control Engineering worked jointly with the authors to develop the new switching, automation, and fault protection schemes. IT Telecom procured and delivered the communications network equipment. Metering Services installed and configured the necessary metering equipment.

Fig. 13 shows the site layout at McAlpine Creek Substation. Fig. 14 and Fig. 15 show the interior and exterior of the control house. Fig. 16 shows the ISO switch with a signal light mounted to provide an easily visible means to see whether the microgrid is islanded. A similar signal light was mounted on the DER switch.



	#	Equipment
Substation	1	Substation
Microgrid Controls	2	ISO Switch
	3	DER Switch
	4	DER Transformer
Distributed Energy Resources	5	Solar Inverter
	6	Battery, Inverter, and Control House
	7	Solar Array
Customer Applications	8	Customer Transformer
	9	Customer Generator
	10	FS24

Fig. 13. Site Layout

Fig. 14. Control House Exterior and BESS

Fig. 15. Control House Interior

Fig. 16. ISO Switch Control With Signal Light

VI. Commissioning

Duke Energy commissioned the microgrid system in early 2015 in cooperation with the personnel from FS24. Load bank testing was performed initially on the microgrid before connecting it to the fire station loads. All applicable battery system operating states were cycled to ensure that the operational response conformed to the design scenarios set forth at the beginning of the project. Islanding and synchronization commands from the microgrid controller were tested across a spectrum of battery and PV work states as well, including battery charging, battery discharging, battery idle, and battery standby. A full checkout of the I/O points was performed to ensure that SCADA could read and control all points assigned to be monitored via DNP3. Event oscillography was obtained from the recloser controllers and meters during commissioning tests to prove functionality and also to provide a baseline for system response that could be tested against in future maintenance intervals.

VII. Lessons Learned

The following subsections cover the lessons learned from the McAlpine Creek microgrid technology pilot project.

A. Microgrids Can Be Valuable Assets

A microgrid can be an asset on the distribution grid. This project demonstrated that near-seamless switching to island mode and seamless transition to grid-connected mode is possible with the use of standard equipment to provide switching and control. The use of these assets for ancillary and grid support functions is fully possible. Customer services can be provided from utility-owned microgrid assets.

B. Nonrecurring Engineering Costs Can Be Large on Brownfield Projects

In this case, the existing equipment was not designed specifically with the control modes necessary for building a microgrid. This made the integration of dissimilar assets a larger task than expected. It required extensive testing to understand the operational limits of the equipment and the system.

C. Inverter-Based Technology Is Challenging to Adopt

The reduction in fault current when islanded must be accounted for in protection settings. Typical overcurrent protection is unlikely to be sufficient. The behavior of the inverter under fault conditions is a function of the control system design. While inverter manufacturers will likely have their own protection schemes, they may not be very forthcoming about the details or the behavior of their proprietary controls.

D. Auxiliary Power Requirements Must Be Considered

Controls and inverters need consistent control voltage to operate through transitions. A CVT can provide this functionality. Uninterruptable Power Source (UPS) systems may be required for communications systems and controls to operate when blackstarting.

E. Power Quality Metering Is Crucial

Power quality waveform-capturing meters are needed to understand switching transitions. Unintended islanding events need to be captured to determine root cause.

F. Safety and Operational Considerations Are Different

Safety and operational considerations are different from existing grid operating methods. Adequate signaling devices should be provided for operators so that they are aware of the state of the microgrid.

VIII. Conclusion

This project saw great success on many fronts, especially in the lessons learned gathered by this team. The use of inverter technology to provide microgrid services is possible provided that proper engineering is applied to fully understand the capabilities and limitations of these resources. Moreover, these resources can be successfully controlled and switched using standard, off-the-shelf utility control equipment, thereby making the process more reliable, more economical, and simpler to implement and maintain for the distribution utility.

Based on their experience with the McAlpine Creek microgrid project, Duke Energy plans to build a larger microgrid at their Mount Holly, North Carolina test lab with a coalition of 25 vendor partners involved [9].

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X. Biographies

Tom Fenimore, P.E, received a BS in Mechanical Engineering in 1978 from Drexel University. He has an extensive background in control systems, energy efficiency, renewable energy, energy storage, and microgrids.

He has been employed by Duke Energy for 25 years in a variety of roles, including Customer Operations, Commercial/Industrial Energy Efficiency, and the Emerging Technology Office. He is currently Technology Development Manager for the Duke Energy Emerging Technology Office and is leading projects including Modular Communications Interface testing, Energy Storage and Distributed Energy Resources Control Algorithm Development, and the McAlpine Creek microgrid technology pilot. He is also an instructor in the North Carolina State University Energy Management Diploma program, board chair for the East Mecklenburg High School Academy of Engineering, and board member for the Institute of Energy Professionals. Tom is a registered professional engineer in the state of North Carolina.

Andy Gould, E.I.T., received a BS in Electrical Engineering Technology in 2013 from UNC Charlotte. Beginning in 2012, Andy worked as an engineering intern for Schweitzer Engineering Laboratories, Inc. (SEL), focusing on transformer monitoring, moisture and gas diagnostics, and load tap changer (LTC) applications. In 2013, he joined SEL full time as an automation application engineer supporting customers with remote terminal unit (RTU), supervisory control and data acquisition (SCADA), communications, and security applications.

Larry Wright, P.E., received a BS in Electrical Engineering in 1982 from North Carolina State University. From 1982 until 2003, he worked for Duke Energy, designing nuclear, hydroelectric, and fossil-powered generating stations for Duke Energy, other utilities, and independent power producers. From 2003 to 2005, Larry served as the subject matter expert on protective relaying for Duke Energy's generating stations. He joined Devine Tarbell Associates in 2005 as Manager of Electrical Engineering, providing consulting services to the hydroelectric industry. In 2008, he joined Schweitzer Engineering Laboratories, Inc., where he is presently employed as a senior protection application engineer. Larry is a registered professional engineer in the state of North Carolina.

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