Implementation of a High-Speed Distribution Network Reconfiguration Scheme

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Abstract—**Traditionally, when a permanent fault occurs on a radial distribution line, all load located downline from the protecting device is lost until sectionalizing and network reconfiguration can be done either locally, by personnel responding to the event, or remotely, by a dispatcher (if SCADA is present). In many instances, a substantial amount of load may be lost and a significant number of customers may be impacted until sectionalizing is performed. With much emphasis now being placed on reliability, there is a need to automate sectionalizing and network reconfiguration to speed up service restoration to as many customers as possible, in order to minimize the impact of a fault.**

Recently Coweta-Fayette EMC, an electric cooperative in Newnan, Georgia, near Atlanta, implemented a high-speed automatic network reconfiguration scheme on a distribution circuit to quickly restore service to unfaulted line sections de-energized by the clearing of a permanent fault. The scheme uses intelligent microprocessor recloser controls and a communications channel between adjacent reclosers to quickly reconfigure the distribution network following a fault.

This paper examines the implementation of the reconfiguration scheme by the utility. Specific settings and operational details of the scheme are given. Additionally, a review of the operational history highlights the impact the scheme has had on the reliability of the utility's distribution network.

I. INTRODUCTION

Coweta-Fayette Electric Membership Corporation (CFEMC) is a member-owned utility located approximately 35 miles southwest of Atlanta, Georgia, serving primarily Coweta and Fayette Counties and portions of six other surrounding counties. CFEMC occupies a new headquarters facility just outside of Palmetto, Georgia, and has a district office in Newnan (Coweta County) and Fayetteville (Fayette County). The CFEMC service territory, crossed by Interstate Highway 85, covers approximately 700 square miles. Its eight-county service territory experienced more than 5% growth per year for the past ten years. The majority of the growth is residential, because the area became a haven for suburban development for the city of Atlanta. CFEMC provides service to Peachtree City, Georgia's second planned community. With thousands of upscale homes and dozens of stores and restaurants where 15,000 acres of Georgia farmland existed 45 years ago, Peachtree City is now the model of a planned community that works—pedestrian-friendly, with plenty of green space. Other cities and developers across the nation are copying parts of the Peachtree City model—especially the golf cart path system that is its claim to fame! The forecast is for continued growth as residential development moves ahead and brings with it the commercial service sector of restaurants, big box retailers, and other support businesses. The CFEMC ten-year forecast predicts serving 102,000 members with a capacity requirement of 665 megawatts.

To meet the need of its continued growth, CFEMC has power contracts with Oglethorpe Power Corporation and Southern Power, Inc. (a Southern Company subsidiary). Oglethorpe Power is a generation and transmission company, owned by 39 of Georgia's EMCs. Formed in 1974, this supply cooperative has met the needs of the Georgia cooperatives through the 1990s. Oglethorpe jointly owns generating facilities with Georgia Power Company and the Municipal Electric Authority of Georgia (MEAG Power). They currently own 30% of two nuclear facilities—Plant Hatch and Plant Vogtle, a 30% ownership in Plant Wansley (a coal-fired facility), 60% of Plant Scherer (coal), 75% of a pumped storage hydro facility, and full ownership of approximately 1200 megawatts of combustion turbines.

In the late 1990s, Oglethorpe's all-requirements contracts were changed, and the EMCs were allowed to negotiate for future energy requirements with other power suppliers, provided they agreed to be responsible and continue to own their share of all the existing Oglethorpe resources. Currently, through this arrangement, CFEMC has ownership responsibility and receives capacity and energy of 400 megawatts through Oglethorpe.

In 2002, CFEMC entered into a long-term power supply agreement with Southern Power to supply its future growth needs, which are expected to be an additional 300 megawatts in the next 10–15 years. With CFEMC's partnerships through Oglethorpe in generation and transmission, CFEMC's energy needs for the near future are well planned for.

At the distribution level, CFEMC provides service in its service area at 12.47 and 25 kV from 23 delivery points, all supplied by transmission voltages 115 or 230 kV. CFEMC currently has 5,565 miles of distribution lines, 2,833 miles of which are underground. Most new residential developments require underground service for which the developer pays, so about 85% of new construction is underground. Because most of the growth is residential, CFEMC's commercial and industrial consumers only account for 6% of the total consumer base and represent about 27% of energy sales.

II. BACKGROUND

In an effort to improve system reliability and service for its members, CFEMC set out to explore the possibilities of im-

plementing an automated distribution network reconfiguration scheme in a pilot project. The cooperative had used microprocessor-based protective devices for several years and had experience with the flexibility that the customizable logic offers. Moving toward an automation scheme seemed to be a logical progression.

After making the decision to go forward with a distribution automation scheme, CFEMC began by identifying a portion of their system to implement the scheme. The criteria for selecting the area included choosing a location where the scheme could make as much impact as possible to improve system reliability and customer satisfaction. Also important was choosing a location where as much existing infrastructure as possible could be used. After evaluating potential locations based on historical outage information and the number and type of customers served, two feeders from different substations, separated by an existing switching point, were chosen. The feeders serve a mix of residential, commercial, and industrial loads. Historically, typical response to perform manual sectionalizing for a fault occurring after business hours on these feeders was approximately 2 hours. While the restoration time was an obvious inconvenience for the residential customers, it resulted in financial losses for the commercial and industrial customers served. Due to the proximity of the area to Interstate 85, there are many restaurants, gas stations, and convenience stores served off the system. There are also larger industrial customers served, such as a concrete mixing facility. It was recognized that improvements made to the restoration time following an event would contribute significantly toward improving customer satisfaction. CFEMC is in an area that allows larger customers to choose their power supplier. Improving service to these customers helps to maintain a healthy relationship with them and consequently makes it less likely that they would choose an alternate power supplier.

Also considered was the existing infrastructure of the two feeders. The feeders chosen had an existing switch between them where switching was typically done during manual sectionalizing and load restoration. Additionally, the feeders had fiber-optic cable on the underbuild of the circuits. Access to the fiber was available if required by the scheme. A map of the two feeders chosen for the scheme is shown in Fig. 1.

With the site selected, CFEMC proceeded to implement an automatic network reconfiguration scheme. The cooperative began looking at the different equipment and methods that could be used to implement a scheme. Various methods were looked at, but ultimately the cooperative decided to implement a custom scheme using the recloser controls they had standardized on for feeder protection. The decision was based on several factors, but most importantly on the fact that the custom scheme could be implemented without adding additional control equipment. The logic capability of their standard control was sufficient to build the custom scheme. Using the standard equipment also meant there would be no learning curve for operations personnel and spare equipment would not have to be purchased because it was already on hand. Additionally,

with the flexibility of the controls, the scheme could be designed to perform exactly as needed.
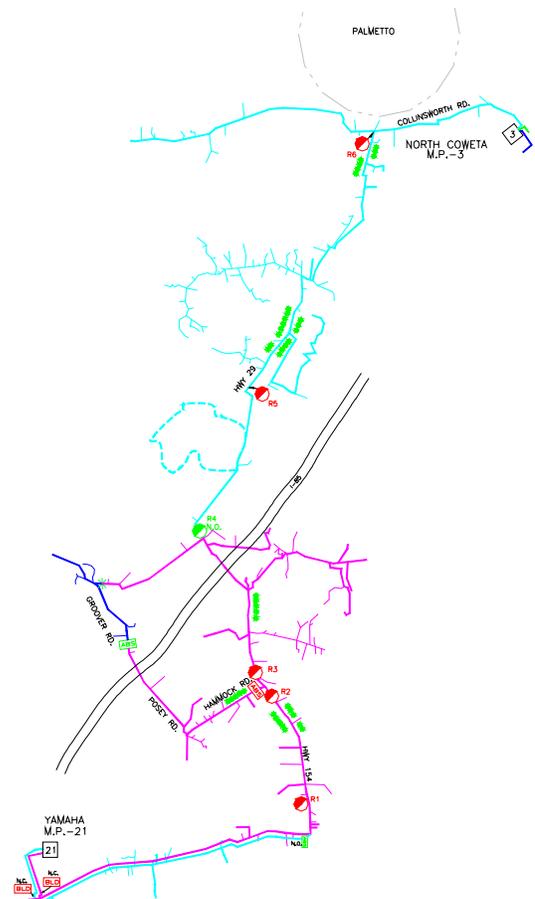

Fig. 1.   System Diagram

III. Implementation

The two feeders that were chosen for the scheme were studied to determine where sectionalizing would be most effective. Six reclosers with microprocessor controls were installed along the feeders, including one to replace the switch at the normally open point. Fiber-optic cable along the feeders was preexisting, so arrangements were made to bring fiber into each control. With the fiber in place, the controls were configured to establish a relay-to-relay communications channel between adjacent controls on the system (Fig. 2). The relay-to-relay communications channel passes eight bits of data between two controls (Fig. 3). Each of the eight bits is transmitted based on the state of a logic equation in the control. A received bit is available to use in logic. The communications protocol was standard in the controls and only required a fiber-optic transceiver to interface with the fiber. The substations at the ends of the feeders used electromechanical relays for protection. It was decided to make every effort to design the scheme to accommodate the existing electromechanical relays and avoid the cost of replacing them. Designing the scheme with this in mind would also avoid the cost of adding fiber-optic cable or radios to provide communications channels to the substations.
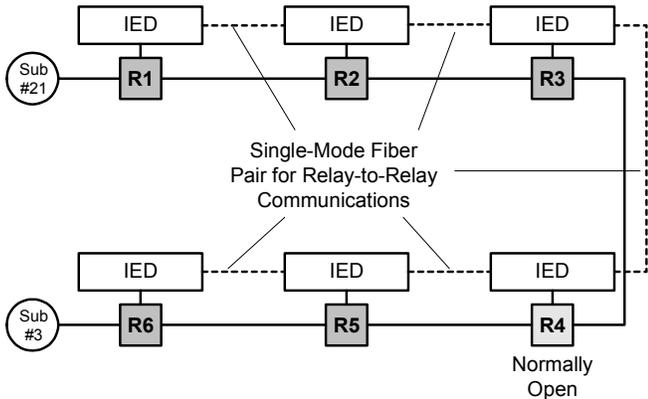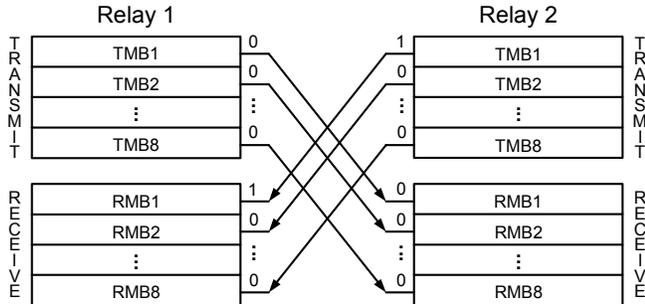
Fig. 2. Communications Diagram

Fig. 3. Relay-to-Relay Communications Representation

IV. SCHEME DETAILS

The objective of the scheme is to minimize the outage time experienced by customers on unfaulted line sections of a feeder following a permanent fault upline. To do this, the scheme must recognize that a permanent fault has occurred, then isolate the faulted line section and close the normally open point to restore service to the unfaulted sections. To operate quickly and securely, the scheme relies on relay-to-relay communications between adjacent devices as described previously. The communications channel is monitored by the control and the communications protocol is secure. As noted previously, the fiber-optic communications do not extend into the substations on either end. The scheme was designed to operate without communications back to the substation to avoid having to replace the existing electromechanical relays and also the expense of providing a communications channel between the substation breaker and the first downline recloser.

A. Operation

Fig. 2 shows an elementary diagram of the system for the automatic network reconfiguration scheme. The R4 recloser is the normally open point, separating the two sources. The logic and settings required for the scheme are relatively simple. Effort was made in the design to make the logic generic so it could be easily applied. Additionally, the logic was designed so the normally open point does not have to be configured in the settings but can change without affecting the operation of the scheme. An added benefit of this is that the scheme is scalable with the settings as they are. Reclosers can be added or removed from the scheme with very little effort.
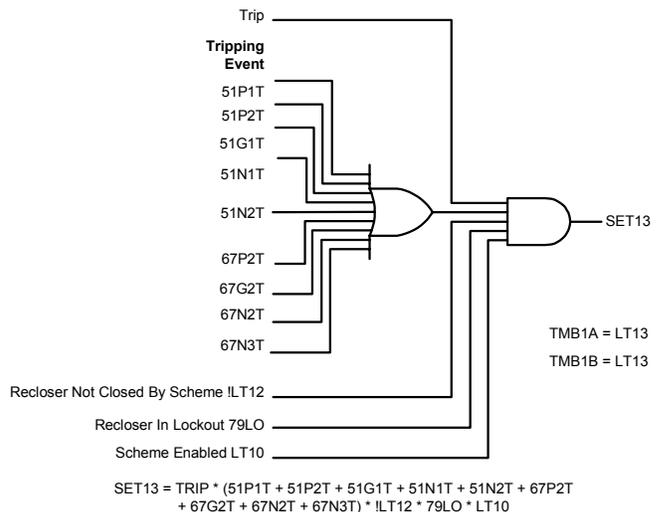

SET13 = TRIP * (51P1T + 51P2T + 51G1T + 51N1T + 51N2T + 67P2T + 67G2T + 67N2T + 67N3T) * !LT12 * 79LO * LT10

Fig. 4. Scheme Initiate Logic

B. Scheme Initiate

For faults occurring anywhere between R1 and R6, the scheme is initiated when one of the reclosers trips to lockout on a predefined tripping element and the scheme is enabled (Fig. 4). This initiate action causes a latch bit to be set (LT13). When asserted, the latch bit causes a bit to be transmitted in either direction by the control.

Because electromechanical relays are used at the substations and there is no communication between the substations and the first respective downline recloser, the scheme operates differently for faults on these line sections (Sub #21–R1 and Sub #3–R6). For faults on these line sections, the controls at R1 and R6 initiate action on loss of voltage. Loss of voltage would indicate that either the substation breaker opened for a fault, or the source to the substation was lost. In either case, the operation of the scheme would benefit customers downline.

C. Scheme Trip

Once initiated, the scheme operates to open the proper control adjacent to the initiating control in order to isolate the faulted line section. For a fault anywhere between R1 and R6, the trip occurs when the control receives a transmitted bit (TMB1) from the adjacent initiating control and the supervising conditions are met (Fig. 5). The supervisory requirements include the conditions that the recloser must be closed, the scheme must be enabled, and the timer that is picked up by assertion of the 50P3 element must not be asserted. The 50P3 element is an instantaneous overcurrent element that is set to detect fault current that would indicate that the fault is downline from the recloser. The timer is on dropout so that the status is maintained until the bit is received from the adjacent control. When the initiating recloser sends a bit in both directions, this timer prevents the upline recloser from tripping by detecting the fault current for this radial system and allowing only the downline control to trip and isolate the faulted line section. Latch bit 11 is set in the logic for these conditions to trip the recloser and prevent reclosing.
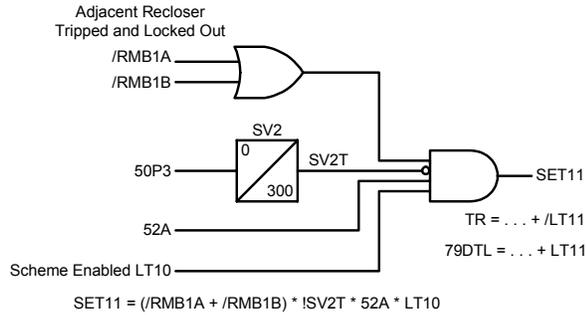
Fig. 5.   Scheme Trip Logic for R2–R5

$$SET11 = (/RMB1A + /RMB1B) * !SV2T * 52A * LT10$$

For faults between the substations and the respective first downline reclosers, the scheme operates differently. In addition to the previously described logic, the controls at R1 and R6 are set to sense a loss of voltage (Fig. 6). The loss of voltage starts a timer that is set longer than any reclose interval that affects the substation. When the loss-of-voltage timer expires and the supervising conditions are met, latch bit 11 is set, which causes the recloser to trip and lock out.
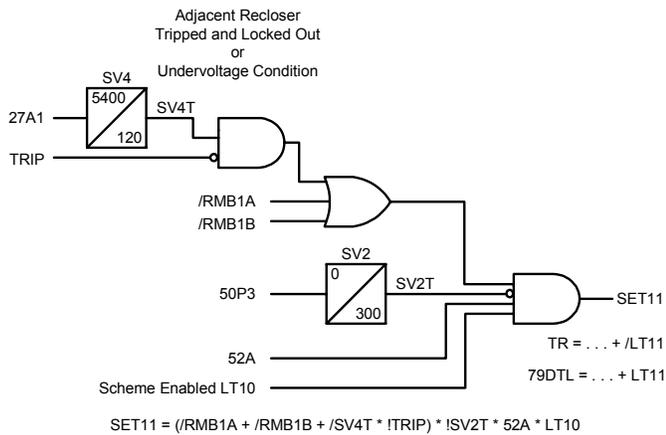

$$SET11 = (/RMB1A + /RMB1B + /SV4T * !TRIP) * !SV2T * 52A * LT10$$

Fig. 6.   Scheme Trip Logic for R1 and R6

D. Send/Echo Close Bit

Once a control opens the recloser to isolate the faulted line section, the control sends a bit downline to close the normally open point and restore service to the unfaulted line sections. This logic is shown in the top portion of Fig. 7. The control transmits bit TMB2 when the recloser indicates open and when RMB1 is still being received from the initiating control.

The bottom portion of Fig. 7 shows the echo logic. This logic is used by the control downline from the isolating recloser to echo the close bit if it is already closed. This allows the scheme to "find" the normally open point.

$$TMB2A = RMB1B * LT11 * !52A + RMB2B * !LT12$$
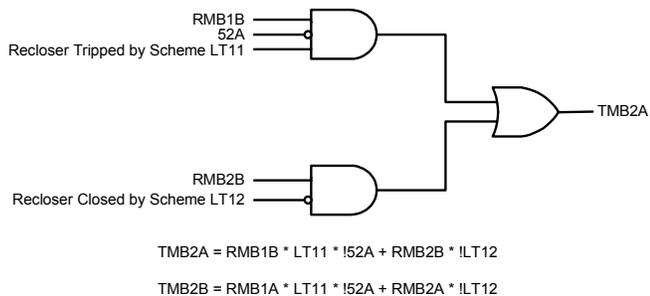
$$TMB2B = RMB1A * LT11 * !52A + RMB2A * !LT12$$

Fig. 7.   Close Bit Transmit Logic

E. Scheme Close

The scheme automatically closes the normally open recloser to restore unfaulted line sections. Scheme close logic is shown in Fig. 8. Latch bit 12 is set when RMB2 is received by a control and the recloser is open. Security is built into the scheme by requiring that the normally open control not be an initiating control (LT13 asserted) or the isolating control (LT11 asserted), and the scheme must be enabled (LT10 asserted). The assertion of latch bit 12 causes the recloser to close and drives a display point.
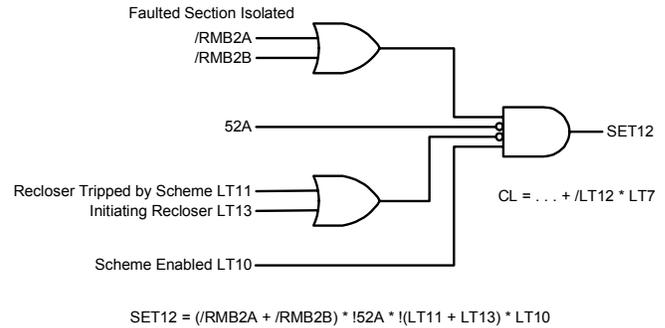

$$SET12 = (/RMB2A + /RMB2B) * !52A * !(LT11 + LT13) * LT10$$

Fig. 8.   Scheme Close Logic

F. Scheme Operation Examples

To illustrate the operation of the scheme, a few examples follow:

1) Permanent Fault Between R2 and R3 (Fig. 9).

The R2 recloser is the primary protecting device for a fault occurring between R2 and R3. When R2 locks out, the line sections R2–R3 and R3–R4 are de-energized. The scheme is initiated when R2 trips to lockout and clears the permanent fault.
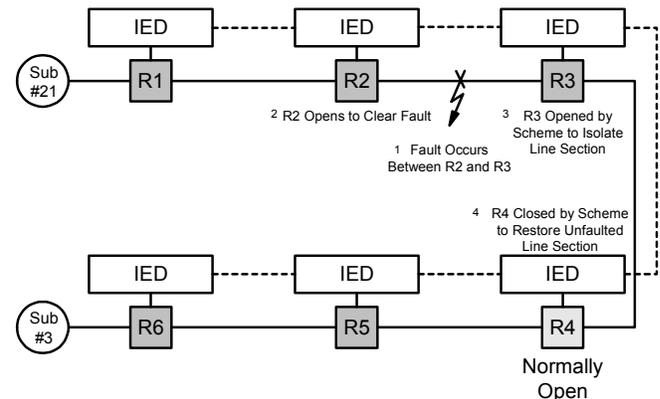

Fig. 9.   Scheme Operation for Fault on R2–R3

Once the scheme is initiated, the control at R2 transmits a bit to the two adjacent controls. Overcurrent elements are used in each recloser in the scheme to identify a downline fault. The overcurrent elements are used to start a time delay on a dropout timer. For this fault, the overcurrent elements in R1 and R2 would have picked up. R1 and R3 receive the bits transmitted by R2 following the scheme initiation. The bit received by R1 is ignored because the timer initiated by the overcurrent element is picked up. The bit received by R3 and the lack of the timer assertion cause the R3 recloser to trip. Once R3 has opened, the faulted line section is isolated. After the R3 re-

closer has tripped and indicated open, a bit is sent by the control at R3 to the downline R4 recloser. Because R4 is open, it receives the bit and closes to restore service to the R3–R4 line segment. It is important to note that the normally open point is not preprogrammed into the scheme, but the scheme is designed to "find" the normally open point and close it. Had R4 been closed, the control at R4 and any additional downline controls would have echoed the close bit transmitted by the control at R3 until the normally open point was found. For this fault location, there is no intentional delay. Once the control at R2 has tripped to lockout, the normally open point should close in the time it takes for the control at R3 to open plus the communications time for the transmitted bits. The 5–10-cycle scheme operate time is negligible to even the open interval times, as the initiating recloser goes through its reclosing sequence and is an obvious improvement over the historical manual switching time.

2) Permanent Fault Between R3 and R4 (Fig. 10).

The R3 recloser is the primary protecting device for a fault occurring between R3 and R4. When R3 locks out, the line section R3–R4 is de-energized. The scheme is initiated when R3 trips to lockout and clears the permanent fault. Once the scheme is initiated, the control at R3 transmits a bit to the two adjacent controls. The overcurrent element used in the control at R2 to identify a downline fault would have picked up for the fault and subsequently the timer would have asserted to prevent opening the R2 recloser when the bit was received. Additionally, because the R4 recloser is already open, the bit would be received by the control at R4 but would not cause any operation. Because no further improvement to the configuration of the network can be made, the scheme action ends.
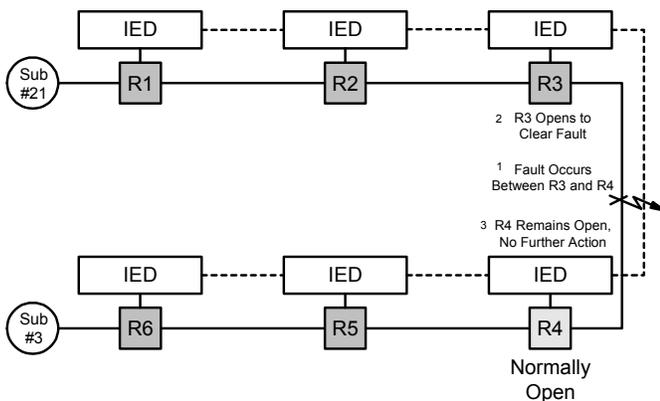

Fig. 10.   Scheme Operation for Fault on R3–R4

3) Permanent Fault Between Sub #21 and R1 (Fig. 11).

Because electromechanical protection is used at the substation serving the feeders, and there is no communications channel between the substation and the downline R1 recloser, the scheme operates differently for a permanent fault between the substation and R1. For this fault, the control at R1 senses a loss of voltage and starts a timer. The timer is set longer than the longest reclose interval of either the substation breaker or the breaker protecting the transmission line serving the substation. The scheme is initiated once the loss-of-voltage timer in the control at R1 has expired, and if there has been no asser-

tion of the overcurrent element used to determine a downline fault. Once initiated, the R1 recloser opens to isolate the potentially faulted line section. Once open, the control at R1 sends a bit to the control at R2. Because the control at R2 is not open, the bit is received and echoed downline to the control at R3. Because R3 is also not open, the bit is echoed to R4. When the control at R4 receives the bit, the recloser closes and restores service to the line sections between R4 and R1. Note that the loss of the Sub #21 substation would cause the scheme to operate similarly. As implemented, the scheme does not differentiate between the loss of voltage due to a faulted line section or the loss of voltage due to the loss of the substation. The operate time for faults at this location would be the loss-of-voltage time (90 seconds) plus the operate time of the R1 recloser, communication time, and close time of the R4 recloser. While operation of the scheme for this fault location is not as fast as for other locations due to the lack of communications back to the substation, the 1.5 minute operate time remains a vast improvement over the manual sectionalizing time.
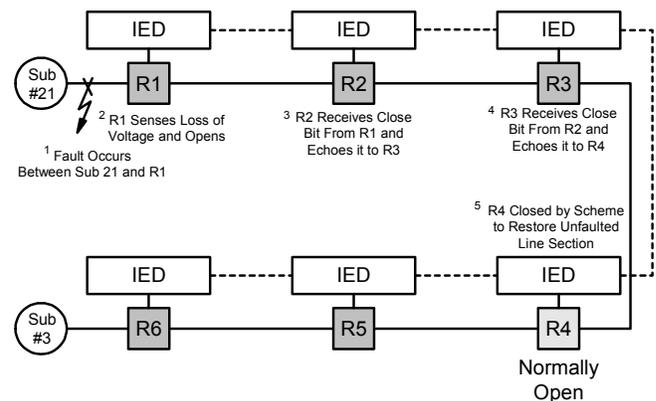

Fig. 11.   Scheme Operation for Fault on Sub #21–R1

G. Operational Details

Because CFEMC did not have SCADA available at the downline reclosers at the time of implementation, every effort was made to add features to the scheme to assist operations personnel during routine operation and also following execution of the scheme for a permanent fault. Because only two of the eight bits transmitted between reclosers were used in the actual operation of the reconfiguration scheme, the six remaining bits were used to enhance the operation of the scheme.

For safety reasons and convenience, the ability to turn the scheme on and off from each of the controls was required. One of the six remaining bits is used in the scheme to indicate the status of the scheme. Disabling of the scheme is done with a pushbutton to deassert a latch bit inside the control. The deassertion of the latch bit at one control causes the control to stop transmitting the status bit to the control(s) adjacent to it. When an adjacent control sees the received indication bit deassert, the scheme is disabled in that control by resetting the latch bit. Subsequently, the status bit is no longer transmitted to controls downline, resulting in the scheme being disabled in all controls. The process of enabling the scheme is similar in that the scheme is enabled at one control with a pushbutton that sets the latch and asserts the status bit. The status bit is

transmitted to the adjacent control(s), which sets the latch and causes the bit to be transmitted downline. This enables all the controls involved in the scheme.

For safety considerations, it was required that the scheme be disabled automatically when a Hot Line Tag was placed or reclosing was disabled at any of the controls involved in the scheme. Because the Hot Line Tag and reclose disable functions were done internally in the controls, this was simple to perform. The latch bits for the Hot Line Tag and reclose disable were included in the reset equation of the scheme enable latch.

With this logic in place, the scheme is automatically disabled at a control when a Hot Line Tag is placed or if reclosing is turned off. When the scheme is disabled at one control, it disables the scheme in the other controls as described previously. Additionally, logic is included to prevent the scheme from being enabled if a Hot Line Tag is placed or reclosing is disabled on any of the controls in the scheme. This is done by transmitting a bit when either of the latch bits for the Hot Line Tag or reclosing disable function is asserted. The bit is received and echoed down the line by adjacent controls so that all the controls have indication of the condition. The Hot Line Tag and reclosing enabled status bit also allow a display message to be generated at each control to notify personnel that a Hot Line Tag is in place or reclosing is disabled somewhere along the circuit (see Fig. 12). This is important because the scheme cannot be enabled while this condition exists, and the display message gives personnel the reason why.

Because communications are critical to the operation of this scheme, special consideration was made to channel monitoring. Status bits for each of the two channels of relay-to-relay communications are available. The status bits are used to prevent enabling the scheme if communications are not healthy in all segments of the scheme. The communication status bits are monitored in each control and if one channel is lost, this condition is transmitted to the adjacent control on the healthy channel and transmitted down the line to the other controls. Additionally, display messages are included to assist personnel in troubleshooting communications problems. If the communications failure is local to the control a "Local Comm Failure" message is displayed. If the communications failure is remote to the control, a "Remote Comm Failure" message is displayed. With this self-diagnostic feature, the scheme allows personnel to easily find the failed fiber section.

With the necessary functions and features of the scheme in place, three of the transmit bits were left unused. SCADA was not yet available on the downline devices; however, it was recognized that any information that could be broadcast throughout the scheme regarding the location of a fault would be helpful to personnel during restoration work. Because there were six reclosers in the scheme, the three remaining bits were used to create a binary code to identify the initiating recloser. The recloser that locks out to initiate the scheme transmits a combination of the bits to identify itself to the other controls in the scheme. Non-initiating controls echo the bits so that the information is available at each control. Different messages were created to be displayed based on the combination of bits

received at each recloser to identify the initiating control. For example, following scheme operation for a permanent fault that causes R2 to lock out, the controls throughout the scheme display the message "Fault on R2" (see Fig. 13).
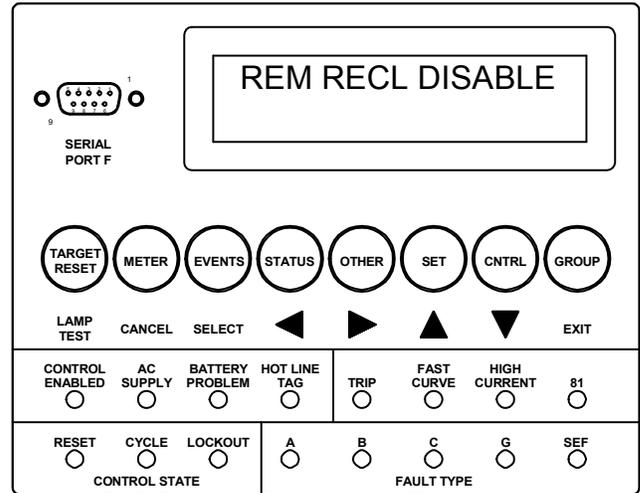

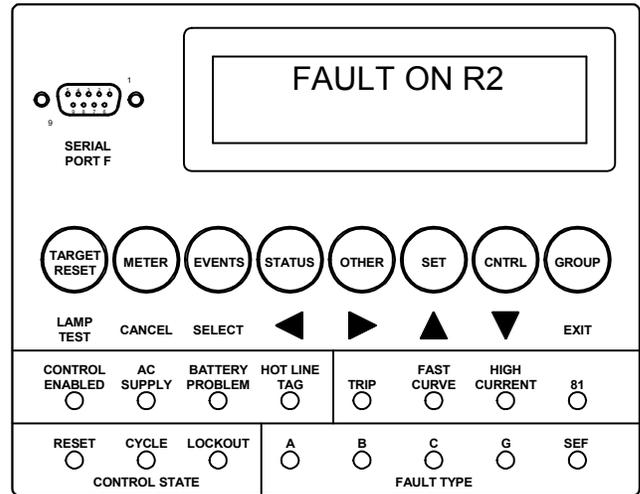Fig. 12. Display Message for Remote Reclose Disabled

Fig. 13. Display Message Following Operation

V. RESULTS

With the scheme in place, the impact that many permanent faults have on the reliability indices is expected to be reduced dramatically. Fig. 14 shows the number of customers subjected to an extended outage for faults at various points along the feeders. Fig. 15 shows the expected impact that the improvements will have on the SAIDI calculations. This calculation is based on the historical data for permanent faults on the feeders. Although the scheme cannot improve restoration time for faulted line sections, restoration time for unfaulted line sections de-energized by the clearing of an upline fault is reduced to under a second for the majority of potential fault locations, and is well under two minutes for faults occurring between the substations and the first downline reclosers. While the improvement in restoration time and impact on the SAIDI numbers can be calculated, the obvious benefit to the customers served and their satisfaction with the cooperative is difficult to quantify.
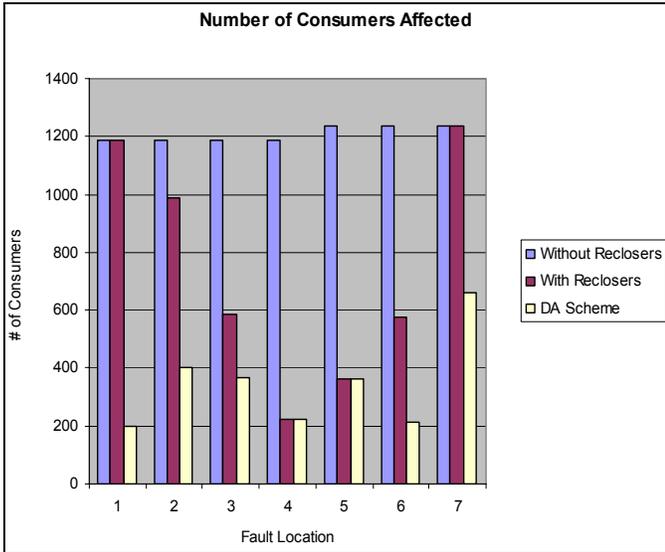
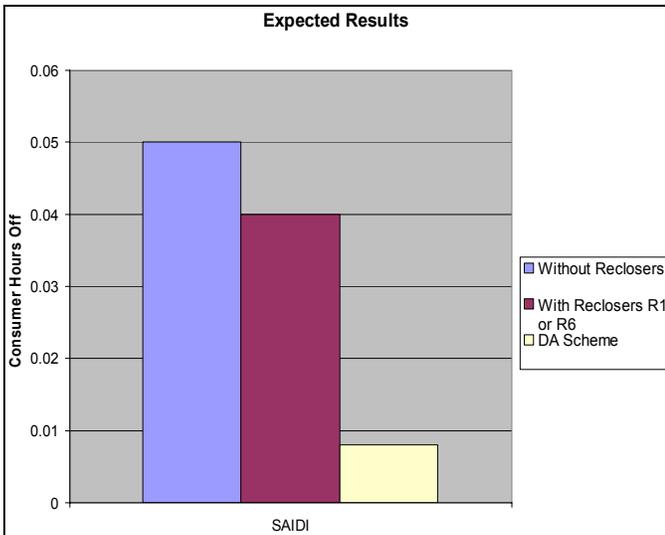Fig. 14.   Number of Customers Subjected to Extended Outage for Faults at Various Points Along the Feeders

Fig. 15.   Expected Impact of Improvements on SAIDI Calculations

VI. FUTURE ENHANCEMENTS

CFEMC has planned to integrate the downline controls used in the scheme into their SCADA system. Once this is done, the recloser initiating the scheme can report this information directly to SCADA. With the information available for the dispatcher, there will be no need to use the three transmitted bits to broadcast the information to the other controls in the scheme. These bits will then be free to be used for other purposes. Of primary interest is implementing a pilot protection scheme so that tripping times can be reduced without sacrificing coordination.

Also in the planning stages is the implementation of the scheme on other feeders in the system. Because fiber-optic cable is not typically available on most feeders, implementation of the scheme with digital spread spectrum radios is being explored.

VII. REFERENCES

[1]   SEL application guide, AG2004-09, "Minimize Distribution Outages With High-Speed Automatic Network Reconfiguration Using SEL-651R Advanced Recloser Controls," June 9, 2004.

VIII. BIOGRAPHIES

Greg Hataway received his B. S. in Electrical Engineering from the University of Alabama in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 12 years at Alabama Electric Cooperative where he worked in distribution, transmission, and substation protection before assuming the role of Superintendent of Technical Services at the cooperative. In this position, he coordinated the utility's efforts in protection and power quality. He joined Schweitzer Engineering Laboratories in 2002 as a Field Application Engineer in the Southeast Region.

Ted Warren received a B. S. in Electrical Engineering from Auburn University in 1993. He has worked as a Senior Engineer in the Protective Equipment Application group at Alabama Power Company and also as a system protection engineer with Alabama Electric Cooperative. He is currently employed as a Field Application Engineer with Schweitzer Engineering Laboratories. Ted is a registered professional engineer in the State of Alabama.

Chris L. Stephens received his Bachelor of Electrical Engineering from the Georgia Institute of Technology in 1991 and his Professional Engineering Certification for the State of Georgia in 1998. He is a member of IEEE. Upon graduating, he worked over two years at Ritz Instrument Transformers, Inc. as a design engineer for CCVT products. Prior to joining Coweta-Fayette EMC in 1996, he worked for Utility Consultants, Inc. as a distribution engineer. While at Coweta-Fayette EMC, he served as Supervisor of Engineering and was responsible for system design and planning including system protection. In 2005, he was promoted to Manager of Engineering.