Improving Distribution System Reliability With High-Density Coordination and Automatic System Restoration

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Abstract—**As more protection devices are added to distribution systems to improve reliability for customers, it becomes increasingly difficult to coordinate operations between the devices while maintaining speed, selectivity, and security. As each new device goes into service, the operating margin between protection devices gets smaller and smaller. As the margin disappears and traditional coordination becomes compromised, we must think of novel ways to increase distribution system reliability while maintaining selectivity and improving the protection of the grid.**

I. Introduction

In this paper, we discuss the concept of high-density coordination (HDC) and immediate partial system restoration that is not reliant on peer-to-peer communications. Such HDC schemes are implemented by Alabama Power Company. We also introduce the concept of coordination groups. Each coordination group is responsible for protecting a specific portion of the line and coordinates with each other via traditional time-current coordination principles. All devices in a coordination group use the same settings, which are likely already determined for an existing application. Finally, we discuss group tripping. All protective devices within the same coordination group trip for a fault located on the portion of the line they are responsible for protecting.

After a group trip occurs, the system begins partial system restoration by reclosing one device at a time. The reclosing of each device is initiated by locally measured voltage. As each device recloses, it enters a high-speed tripping mode to provide coordination with upstream devices and quickly clears permanent downstream faults. We refer to this as "stepped reclosing." This scheme allows for any number of protective devices to be added to a system while maintaining speed, selectivity, and security.

II. Distribution System Reliability Metrics

Distribution utilities aim to provide reliable electricity service to their customers, while faults in the distribution system lead to interruptions that challenge system performance. A measure of the distribution system's performance based on its response to these system events is made through metrics that take into account the frequency and duration of these interruptions, as well as the number of customers affected. Some of the indices commonly used by distribution utilities are System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), which consider sustained interruptions. An interruption is classified as sustained if it lasts more than five minutes [1] in many regulatory jurisdictions. A momentary interruption is one that causes a brief loss of power delivery to one or more customers caused by the opening and closing of an interrupting device. This sequence of operations from the recloser (all open and close operations) is counted as a momentary interruption if the loss of power is less than the threshold used by that utility to define momentary.

The basis for the calculation of these indices is the total number of customers interrupted (CI) and customer minutes of interruption (CMI). CMI is the number of customers affected multiplied by the number of minutes of interruption. N_T is the total number of customers served. The calculation for these indices is as shown:

$$\text{SAIFI} = \frac{\text{CI}}{N_T}$$

$$\text{SAIDI} = \frac{\text{CMI}}{N_T}$$

$$\text{CAIDI} = \frac{\text{CMI}}{\text{CI}}$$

A. High-Density Installation of Protective Devices

While a distribution utility can improve system reliability by minimizing the likelihood of system faults, eliminating system faults altogether is not possible, as the system contends with natural phenomena including storms, wind, lightning strikes, and damage due to animals, along with faults caused by people such as vehicle collisions with power poles. However, methods to reduce the number of customers affected by an interruption can be implemented. This typically involves the installation of more interrupting devices in the system to reduce the number of customers affected by the operation of protective devices. For example, consider a radial feeder starting at a substation breaker with one downline recloser. The customer distribution is as shown in Fig. 1. For a fault that causes the recloser to lock out, 300 customers will experience a sustained interruption. If it takes 100 minutes to repair the faulted section and restore service, the CMI is 300 • 100 = 30,000 minutes.

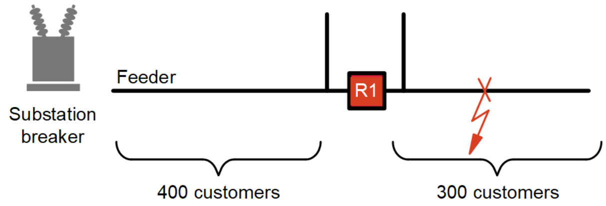

Fig. 1. Fault downline of Recloser R1.

Now, consider the case where additional reclosers are installed in this feeder, with the customer distribution shown in Fig. 2. In this case, the permanent fault is between Reclosers R6 and R7. When Recloser R6 correctly locks out, 200 customers downstream experience an interruption. Overall, the high density of protection devices positively impacts the system reliability with improved SAIDI and SAIFI.

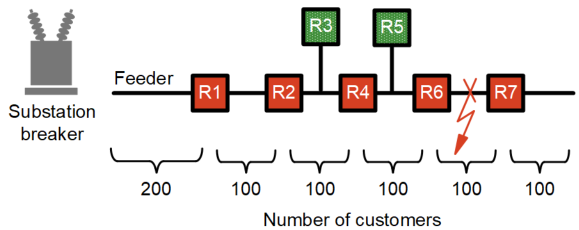

Fig. 2. Fault downline of Recloser R2.

B. Challenges in Maintaining Coordination With a High Density of Reclosers

Selective coordination between reclosers on a distribution system is traditionally achieved using time-current coordination. With only a few reclosers in series, there is adequate coordination margin available between the time-current curves of each recloser. This is illustrated in Fig. 3.

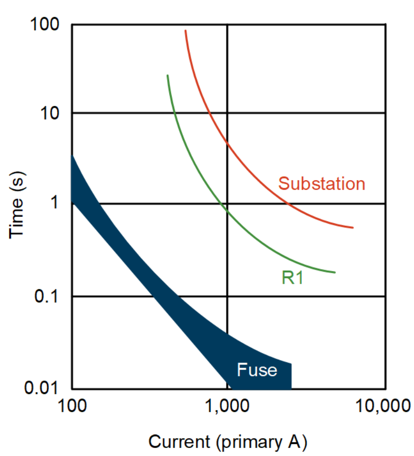

Fig. 3. Limited number of devices allow adequate coordination margins when traditional coordination methods are used.

As the density of recloser installation increases in the distribution system, this margin is reduced, and it becomes more complex to set these recloser controls using traditional coordination practices. The inverse-time overcurrent curves for each of these reclosers are bounded by the downstream protection operating speed and substation transformer damage curves, as shown in Fig. 4. With each new recloser added, the coordination time intervals can be reduced, and selective coordination between reclosers can be compromised. This results in multiple reclosers tripping for a fault and leaves more customers than necessary experiencing a sustained interruption, defeating the purpose of adding more reclosers to the system. Further, each new recloser added may require the development of new settings for the other reclosers in the dense recloser installation. Additionally, with interconnected networks, the system is not always in a normal configuration and coordination studies must be performed for multiple power flows due to alternate configurations. High-speed communication can overcome this challenge [2]. However, not all utilities are able to implement a high-speed communications-based infrastructure for all intelligent protective devices in their system. Therefore, in a high-density installation, a new method to simplify settings and to get the right device to lock out (even in alternate system configurations) without high-speed communications is desirable. This is explained further in Section III.

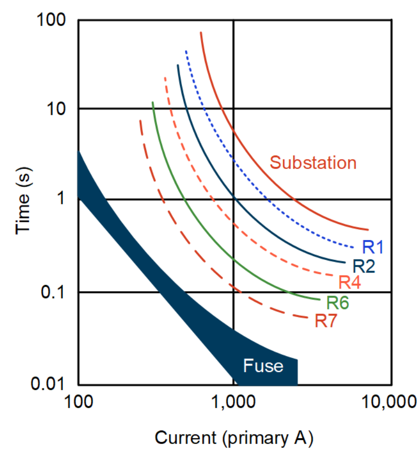

Fig. 4. Reduced coordination margins with traditional coordination methods increase the risk of multiple devices locking out.

In both Fig. 3 and Fig. 4, the inverse-time overcurrent plots include a curve for a fuse. This specific example is showing that the scheme is implementing a fuse-blowing approach. The implementation of HDC does not have to be exclusively used with fuse blowing. However, it is important to acknowledge the difference in behavior of the overall system protection if a fuse-saving approach is being implemented instead. Of significance is the fact that for a fault located downstream of the fuse, HDC will temporarily operate all reclosers in the upstream coordination group of the fuse before eventually causing a single recloser control upstream of the fuse to lock out.

III. A New Approach to Coordination

Traditionally, distribution engineers have implemented schemes to allow additional interrupting devices to be installed onto the system at specific locations to reduce the number of customers that are impacted by a permanent fault. One example of this would be to use a sectionalizing device. The idea behind this logic is to identify when a permanent fault is downstream of the sectionalizing device. After a fault has been detected and cleared by a device capable of breaking fault current, the sectionalizer uses fault current to count the number of through faults to which it has been exposed. If the sectionalizing device determines the fault was downstream, it operates (opens) to isolate the fault. Typically, the sectionalizer counts faults and opens (while the local system is still de-energized) after a predetermined number of faults have occurred [3]. Using this method, all loads upstream of the sectionalizer are unaffected by the permanent downstream fault. This method is effective in reducing the number of customers impacted by a fault, but it has its limitations. The sectionalizing device is not capable of breaking fault current, so it does not participate in the protection scheme. The settings and logic used by a sectionalizer are unique to its application, and thus, it adds complexity to the system's protection scheme. Also, because the sectionalizer count must be set to one less than an upstream device's reclose or sectionalizing count, there is a finite number of sectionalizers that can be installed downstream of any interrupting device. Sectionalizers were originally hydraulic devices not used with microprocessor controls; however, in recent years, sectionalizing logic is more commonly being implemented on reclosers via microprocessor recloser controls. This provides the added benefit of acquiring both fault and SCADA data from the sectionalizer location. But even when microprocessor recloser controls are used to implement classical sectionalizing behavior, the method is still subject to the same limitations.

The method of HDC recognizes that there is still a limited number of interrupting devices that can be selectively coordinated with each other. As such, the method breaks up the system into coordination groups. All of the recloser controls in the coordination group use the same exact protection settings. Each coordination group is treated as a single recloser control, and so the number of coordination groups is limited to the number of recloser controls that can be selectively coordinated. This reduces the complexity of the system's protection scheme as there is no longer a need for separate logic based on the application of the recloser. Traditional time-overcurrent coordination concepts are then implemented to coordinate between coordination groups. The boundary between coordination groups is easily identified as it is the location(s) in the system where there is enough margin on the time-current coordination curve to properly coordinate operations between each group. However, there is no practical limit to the number of recloser controls that can be in a coordination group, and as such, there is no limit to the number of recloser controls that can participate in an HDC scheme.

As previously discussed, all recloser controls in a coordination group use the same exact protection settings. This means there is no attempt to coordinate between individual recloser controls. The lack of coordination between individual recloser controls within a given group means that it is common for multiple reclosers in a group to operate for a fault that is located within the protective zone of reclosers in that group. Traditionally, this would be referred to as a miscoordination, as the recloser closest to the fault is not the only device to operate. However, HDC is aware this condition is likely to occur, and it has logic to compensate for it by reclosing each recloser in a controlled sequence. The logic is explained in more detail in the next section, but this introduces a consideration that users should make when determining the number of reclosers to apply in a coordination group. Because each device is reclosed in sequence, each after a short time delay, a higher device count in the coordination group implies longer open intervals for recloser controls on the downstream end of the group. Users may want to limit the number of recloser controls in a coordination group to ensure momentary interruption events are still shorter than the window required by their regulating bodies.

It is important to understand the system and operational requirements for HDC to be implemented. The scheme presented here is designed for a radial system, and the interrupting device is capable of breaking fault current. The recloser control measures voltage from at least the source side of the recloser, provides dual-characteristic time-overcurrent elements, and supports a method to secure high-speed overcurrent elements for transformer inrush conditions.

IV. Logic Implementation

HDC (without peer-to-peer communications) is a system-wide protection approach. The simplest and most effective way to teach the concepts of this scheme is to look at an example system and walk through a sequence of events that cycles through the states of HDC logic. It is important to note all recloser controls in a coordination group have implemented the exact same protection settings. The varying states of HDC without peer-to-peer communications are as follows:

1. The recloser controls detect a fault – A fault downstream of the recloser control triggers the logic checks that will determine if HDC is necessary or not.
2. The recloser controls check the voltage – After the fault has been cleared, each recloser control that detected the fault checks to see if it is measuring healthy voltage.
3. The recloser controls activate HDC restoration – If no voltage is measured on either side of a recloser installation (and it had seen the fault current), activate HDC restoration logic in the recloser control. It is important to note that the first recloser control in a coordination group is unique. It will always measure healthy voltage on the source side of the recloser control for all faults in the coordination group. Thus, it will not activate HDC restoration logic. The recloser control is programmed to reclose after a TRIP, which starts the HDC restoration process as described in States 4–9 for the rest of the coordination group.
4. Each recloser control is in the TRIP state – Each recloser control that has HDC restoration logic active must be in the TRIP state. If the recloser control has not tripped as indicated by the breaker status of the device, the restoration logic issues a TRIP command to the recloser. Once all recloser controls in the coordination group that saw the fault have tripped, they enter a wait period that does not end until the recloser control measures healthy voltage.
5. The recloser control issues a CLOSE command – The recloser control that measures healthy voltage on its

source side (there will only be one) will begin its autoreclosing sequence and issue a CLOSE command.

6. The recloser control enables a fast time-overcurrent element – As each recloser control issues a CLOSE command, it simultaneously enables a fast time-overcurrent element. It is important to note that the overcurrent element is supervised with second harmonic detection to provide security for transformer inrush conditions that may be present when energizing the downstream line segment. The fast element is only enabled for a brief period of time.
7. The recloser controls sequentially issue CLOSE commands – The first recloser control that detects healthy voltage after the fault event then issues a CLOSE command, resulting in healthy voltage applied to the next downstream recloser control in the coordination group. This next recloser control waits a short time before continuing with a similar reclose operation. This brief delay, called stepped reclosing, provides time to see if a fault ignites or reignites on the newly energized line section (e.g., some fault resistance conditions may need to be "burned through").
8. The already closed upstream recloser reverts to delayed time-overcurrent protection before the downstream adjacent recloser control issues a CLOSE command – This provides coordination with the downstream recloser control, as it will enable a fast time-overcurrent element when it issues the CLOSE command as previously discussed in State 6. This subtle detail is what allows the recloser controls to use the same time-overcurrent settings in a coordination group. A fast element enabled when reclosing will provide the necessary coordination with upstream recloser controls if it closes into a fault. The fast element provides the additional benefit of reducing fault incident energy without sacrificing selectivity. This premise has been applied for years in transmission protection as Switch-On-To-Fault (SOTF) logic and has been applied in distribution systems to limit through fault effects on transformers and feeder conductors. If the fault is permanent, it will lock out that device. Alternately, a successful reclose operation means the fault is not permanent or not in the segment it closed into. This will turn the fast element off after a brief period of time and change back to the slower curve.
9. This stepped reclosing process continues at each recloser control in the coordination group until either a permanent fault is located, in which case the recloser control trips and recloses until lockout, or all recloser controls in the coordination group successfully reclose, indicating that the fault was temporary in nature, and all recloser controls can go back to normal operating mode.

We will now look at a scenario that applies system conditions to devices and the response of each device. In our example system shown in Fig. 5, we apply a permanent fault between Reclosers R6 and R7. This provides a good example because it shows the states that each device in the coordination group are in and also shows how customers on this feeder would benefit from this scheme compared to a feeder that is only protected by a substation breaker device that would result in the entire feeder being de-energized for the permanent fault. Note that in this figure solid red boxes are closed reclosers and the textured green boxes are open reclosers.

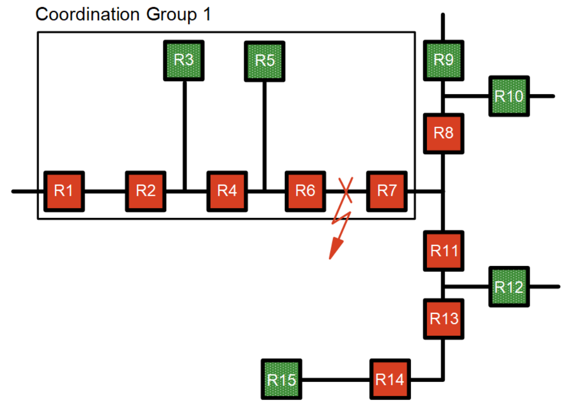

Fig. 5. Fault applied downstream of R6.

The fault downstream of R6 causes Reclosers R1, R2, R4, and R6 to operate. The fault is upstream of R7, so it does not operate for this fault even though it is part of Coordination Group 1. A breaker relay is coordinated in a traditional sense with Coordination Group 1, and it does not operate for this fault. Keep in mind, this is the expected result because all recloser controls are using the same time-overcurrent settings. In Fig. 6, all reclosers in Coordination Group 1 progressed through States 1–4, with the exception of Recloser R7 that remains in State 9 because it does not detect the fault. Recloser R1 will have healthy voltage on the source side, and it will transition to State 5, while all other devices stay in State 4. The state of each recloser is shown above it.

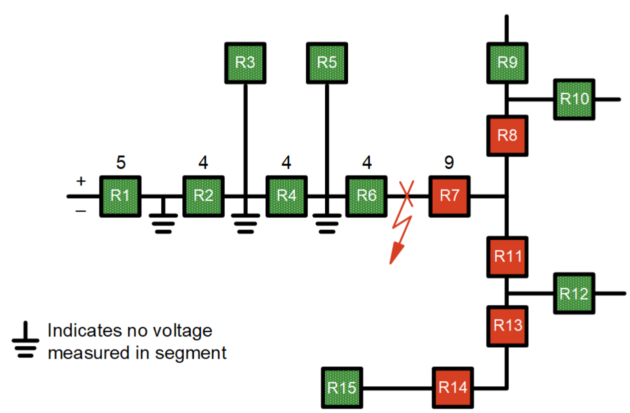

Fig. 6. Stop reclosing begins at R1.

As Recloser R1 progresses through its reclosing sequence, it will eventually enable the fast time-overcurrent element and issue a CLOSE command. In Fig. 7, as R1 closes, R2 moves into State 5 while the other recloser controls are still waiting for healthy voltage.

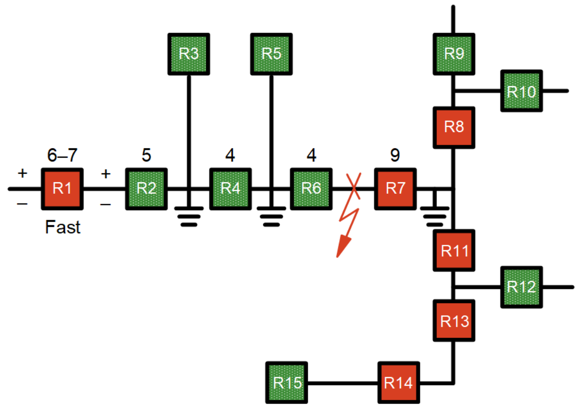

Fig. 7. R1 issued CLOSE.

After R1 closed, R2 measured voltage and started its reclosing sequence. Before R2 issues CLOSE, R1 must be using a delayed curve. This transition does not have to happen simultaneously, but the order of operations is important. R1 must have its time-overcurrent delay curve element enabled prior to R2 closing. As Recloser R2 progresses through its reclosing sequence, it will eventually enable the fast time-overcurrent element and issue a CLOSE command (see Fig. 8).

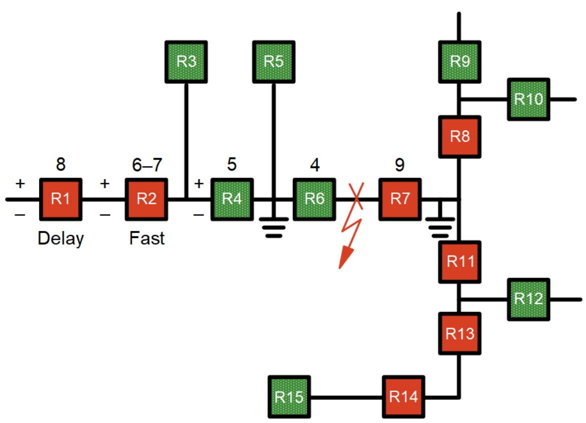

Fig. 8. R1 and R2 successfully reclose.

After R2 closed, R4 measured healthy voltage and started its reclosing sequence. Before R4 issues CLOSE, R2 must revert to the delayed curve to provide the necessary coordination with R4 when it issues a CLOSE command. In Fig. 9, R1 transitions to State 9 because it is back to its normal operating mode.

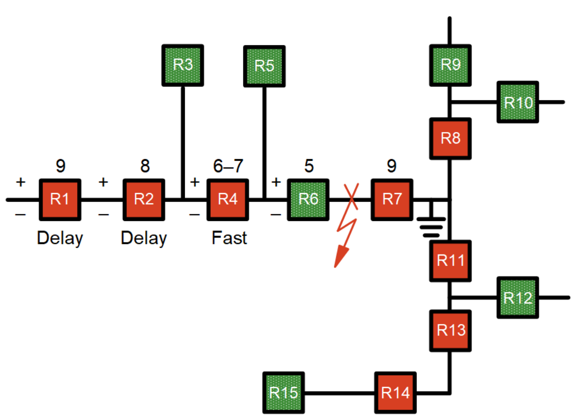

Fig. 9. R6 closes into fault.

After R4 closed, R6 measured voltage and started its reclosing sequence. Before R6 issues CLOSE, R4 must revert to the delayed curve. R2 transitions to State 9 because it is back to its normal operating mode.

R6 closes into the fault. However, it is the only recloser control that is operating on the fast time-overcurrent element, and thus, it is the only recloser control that trips. To indicate that the reclose was not successful, the box is half green and half red in Fig. 10.

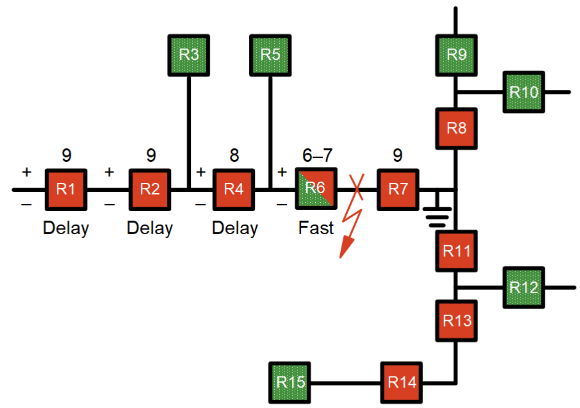

Fig. 10. R6 closes into fault.

Recloser R6 attempts to CLOSE for the number of shots for which it was programmed. When the recloser control reaches its maximum number of shots, it will lock out, which in this case was the correct and expected operation for the permanent fault. The system after HDC restoration has been restored up to the location of the fault in Fig. 11.

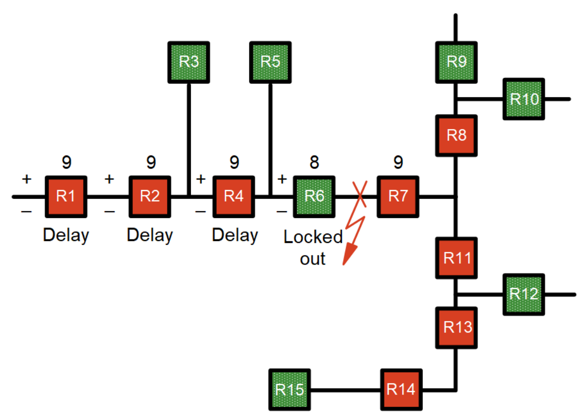

Fig. 11. System restored to the fault location.

Fig. 11 demonstrates that only the customers downstream of R6 are impacted by this fault. Later in Section VI, we explain how SCADA data from all of these reclosers can be used to reconfigure the system to even further reduce the number of customers impacted by permanent faults. Comparing the HDC restoration scheme to a system that only has a relay at the substation because of coordination concerns, we can see that the HDC scheme allows the utility to continue to serve all customers between the substation and the fault.

V. Additional Benefits of HDC

The obvious benefit of HDC is knowing that the recloser controls in a coordination group operate in a coordinated fashion to lock out the recloser closest to a permanent fault. This has always been the goal in distribution protection schemes. However, there are added benefits that may not be obvious to the user. These benefits include:

- Reduced settings complexity – Reclosers in a dense installation that cannot achieve standard coordination are usually programmed as non-fault interrupting switches or sectionalizers. This implementation adds complexity as it requires different protection and logic settings. The HDC solution presented here allows all reclosers to be set similarly.
- Accurate fault location – Historically, locating faults in distribution systems has been a challenge for protection engineers [4]. As the stepped reclosing occurs and a device transitions to the locked-out state, the fault has been located to the downstream line segment of that device. HDC provides accurate fault location even when the system is in an alternate configuration as it is not reliant on the system's impedance characteristics.
- Mitigation of conductor slap – The HDC logic inherently mitigates the challenges traditionally faced by a conductor slap event. Typically, a conductor slap event can cause recloser controls to miscoordinate [5]. However, HDC logic is designed to accommodate miscoordination, and thus, it can also correct for miscoordination caused by conductor slap events.
- Fast fault clearing – After the initial fault as each recloser begins its closing sequence, the recloser control enables the fast curve time-overcurrent element. This ensures that if and when we close into a fault, it is cleared as quickly as possible, reducing incident energy of the fault.

VI. After Lockout Is Detected

This section introduces an additional concept to reduce the number of customers impacted by a permanent fault. There have been numerous names used to describe this method throughout the industry, but some common terms are network automation, smart grid, and fault location, isolation, and service restoration (FLISR). Although there may be differences in the implementation and complexity of each scheme, the goal is to identify where a fault has occurred, lock out the appropriate recloser controls to isolate the fault, gather system information to determine if and how a system can be reconfigured to serve the maximum number of customers, and then control normally open locations to reconfigure the system to achieve the goal of reducing customers affected by a fault.

While the purpose of this paper is not to go into great detail on these schemes, we do want to mention that these schemes are not active until a device on the system has locked out. Therefore, HDC and service restoration complement one another, as shown in Fig. 12. HDC is used in the time from fault inception to lockout, and then the schemes that have access to information from more devices in the system can restore the remainder of the system. These schemes can be used together or in isolation.

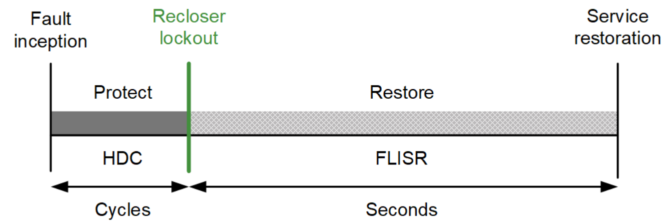

Fig. 12. HDC hands off to system restoration.

VII. Alabama Power Company's Story of Improved Metrics

Thus far, we have presented the concept of HDC using coordination groups, group tripping, and stepped reclosing to ultimately lockout the correct recloser, with no dependence on communication between devices. However, any new idea is best justified by sharing the results of an application. Since implementing this technology, Alabama Power Company has installed this logic on a total of 696 recloser controls as of July 2022. While many of these implement the logic as a backup to communication-assisted schemes, several of these locations use the logic described in this paper as the primary means of selectively locking out the correct device to minimize sustained interruptions to Alabama Power's distribution customers.

In April 2021, a rural feeder on the Alabama Power system experienced a permanent fault caused by the failure of an overhead switch in the section between Reclosers R3 and R4 as shown in Fig. 13. The protection on this feeder is implementing concepts of HDC discussed in this paper. Prior to HDC, R3 would not have been installed, and the same outage would have been cleared by R2, affecting 930 customers. Instead, even though R1, R2, and R3 all tripped, the stepped reclosing logic restored R1 and R2 and allowed R3 to close on its fast curve, then trip to lockout. The HDC scheme operated as designed, which resulted in only 828 customers being impacted. This prevented a sustained interruption to 102 customers. It also isolated a smaller segment of the feeder, which resulted in crews needing to inspect only one mile of line between R3 and R4 instead of over two miles of line between R2, R8, and R4.

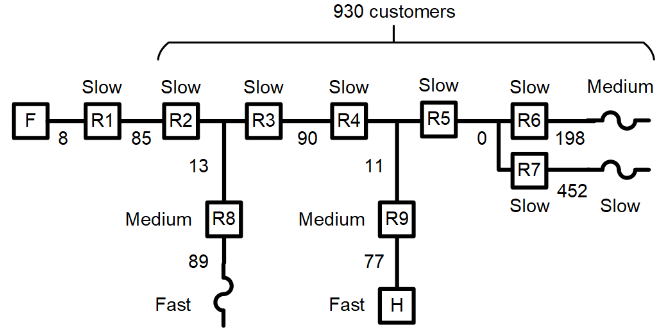

Fig. 13. Alabama Power Company feeder using HDC logic.

Since this feeder serves 1,023 customers in total, the HDC scheme reduced the contribution to SAIFI by 0.1. The actual interruption duration was 48 minutes but could have been 50 percent longer (72 minutes) with more line miles to inspect. There were 102 customers who did not experience a 72-minute interruption, and 828 customers who experienced a 24-minute shorter interruption. This implies a reduction in CMI of 72 • 102 + 24 • 828 = 27,216 minutes. With 1,023 customers in total, the HDC scheme reduced the contribution to SAIDI by 27 minutes.

The feeder in Fig. 13 also shows how a fuse can be included in an HDC scheme. Reclosers R1 through R7 and the fuse marked "Slow" are all members of the same coordination group. For a fault downstream of the fuse, the fuse will blow, but R1, R2, R3, R4, R5, and R7 will all trip as well. However, the stepped reclosing of the HDC logic will restore all of the reclosers that tripped, leaving only customers downstream of the fuse in a sustained interruption.

VIII. Conclusion

Alabama Power Company is adding additional recloser controls on their distribution system to reduce the number of customers that are impacted by a permanent fault. The additional reclosers have compromised Alabama Power's time-overcurrent coordination. Thus, Alabama Power developed HDC logic that is not reliant on peer-to-peer communications to coordinate their protection. This paper discusses the logic in detail and shares a real-world example from Alabama Power's system showing the improved reliability metrics.

This paper also discusses additional benefits of using HDC logic which include reducing setting complexity, improving accurate fault location, mitigating the effects of a conductor slap event that causes miscoordination, and fast fault clearing of permanent faults. These benefits are achieved as a byproduct of using HDC logic and require no action to be taken by the user. Also, we describe how HDC and distribution automation schemes complement one another to provide a solution that provides speed, sensitivity, and selectivity to clear faults, lock out the appropriate devices, and reconfigure a system to reduce the number of people impacted by a permanent fault, thus, improving reliability metrics.

IX. References

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X. Biographies

John Thorne has 20 years of experience at Alabama Power Company, serving in various distribution engineering positions. He has experience in construction, protection, and reliability at the company. He presently holds the position of Power Delivery Test Lab team leader. He received his BS in electrical engineering from Auburn University in 2004.

David Nahay has eight years of experience at Alabama Power Company, serving in various distribution engineering positions. The primary focus of his career has been reliability, protection, and distribution automation. He works at the Power Delivery Test Lab and holds the position of senior engineer.

Cole Salo has a BSEE from Montana Tech. He joined Schweitzer Engineering Laboratories, Inc. (SEL) as an intern in 2008 and was then hired as a product engineer in 2009. At SEL, he has held roles supporting and developing distribution, transmission, and transformer products. He is currently a senior product engineer working in the distribution, controls, and sensors division supporting product applications along with the development of new products.

Jeremy Blair earned his BSEE from Louisiana Tech University and his MSECE from Georgia Institute of Technology. He joined Schweitzer Engineering Laboratories, Inc. (SEL) as an application engineer in 2013, authoring conference papers and application guides and assisting customers with relay and distribution automation solutions. Previously, he worked for Entergy Corporation as a distribution planning engineer with responsibilities in distribution system planning, protection, power quality, and automation. He also managed Entergy's Automatic Load Transfer and Sectionalization Program over its four-state territory. He is a licensed PE in Louisiana.

Gautham Ashokkumar earned his BE in electrical and electronics engineering from R.M.K. Engineering College (affiliated with Anna University) in 2013, and he earned his MS in electrical engineering from Missouri University of Science and Technology in 2017. His master's degree specialized in the field of power system engineering, including power system protection. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL), he worked in electrical maintenance and operations in India. He joined SEL in 2017 as an associate application engineer in protection. He currently works as an application engineer in Alpharetta, Georgia.

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