Overcurrent Protection Coordination in Automated Distribution Feeders

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Abstract - **Automating distribution feeders can present many problems to protection engineers. The basic philosophy in distribution feeder automation is to break a feeder up into line segments using reclosers or load break switches. Each line segment supplies power to a number of consumers and it can be fed from alternate substation sources. When a substation source is interrupted to a line segment, the automation system must reconfigure the feeder system to get power from an alternate substation source. When this reconfiguration of the topology takes place, the overcurrent coordination settings must be adapted to the new feeder topology.**

A protection device can easily run out of setting groups to address each topology. Actively adaptive protection systems might be a solution but will require system wide knowledge communicated to it or between all devices and the calculation capability to adapt the settings immediately after every switching action in an automation sequence.

In this paper, the authors develop a protection standard supporting feeder automation across the entire distribution network while requiring only a single set of overcurrent curves for coordination of multiple automation devices in series between the substation devices and lateral fuses. This is achieved with a total of 4 sets phase and ground curves. One standard set for the substation devices to coordinate with one standard set for the automated field devices that will coordinate lastly with a wide variety of lateral fuses and single-phase reclosers. A 4th set of curves is used to interconnect independent automation groups to form a modular deployment approach. The protection system devices quickly locate the fault and communicate among devices to release the overcurrent curve of only the correct device to execute the coordinated tripping action. The system discussed in this paper is installed and functional using cellular modems for peer to peer communications.

I. INTRODUCTION

Distribution feeder automation systems that are available today provide many different approaches to find a solution to improve the reliability of distribution feeders.

The primary reliability improvement functions these systems provide include fault locate, isolate and service restoration (FLISR) and automatic transfer functionality (ATS). These functions greatly improve the reliability KPI's of distribution feeders, and can vary in architecture between centralized, decentralized or a combination of both. Centralized systems have traditionally been the solution of choice to automate distribution feeder networks.

These systems must wait for the protection systems to disconnect faults in the network before they can act to locate the faulted feeder segment, reconfigure the feeder, and supply alternate power to unaffected areas of the network.

Decentralized systems, by contrast, provide the capability to synchronize protection and automation functionality in the field devices to provide faster fault isolation and system configuration actions.

Furthermore, centralized systems are restricted in the number of topology changes they can perform based on the protection systems' flexibility to accept the changes. With decentralized systems however, the protection system and the automation system can better adapt to topology changes.

KUB decided to use a decentralized approach to automate and protect their distribution feeders in that it will better suite their deployment and performance requirements.

This paper will discuss the system that KUB selected, the systems deployment difficulties, and a new solution that was developed from an existing system and deployed in the field to solve all the deployment concerns of KUB and potentially other Utilities.

The paper will include background information of the basic functionality of a Distribution Feeder Automation System, discuss the standard system functionality of the system KUB selected and then the adaptation KUB required to be implemented including the communication system to make the system deployable on the KUB distribution grid.

II. Traditional Approach

The traditional approach consists of two distinctly different functions, protection first and then automation.

- The protection system disconnects the fault from the network through coordinated over current tripping and auto reclosing actions.
- The automation system then locates the faulted line segment of the feeder, isolates this faulted segment, and executes automatic closing of a field primary switch to provide alternate power from a different power source to unaffected feeder line segments.

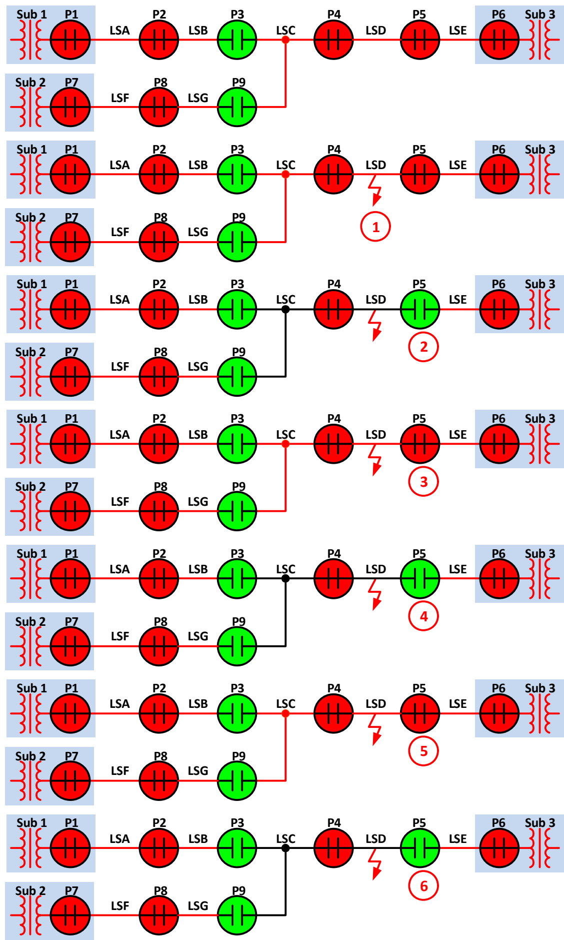
The following figure will illustrate the many different steps that are needed in order to isolate the faulted segment in the feeder and provide alternate power to unaffected line segments.

The system consists of substation and field reclosers which are interconnected to provide the capability of isolating any line segment and providing alternate substation sources to all line segments.

Please refer to Fig. 1. which illustrates protection functions for a permanent fault located on line segment D. (Note that the recloser controllers are set to three shots to lockout).

The protection devices are configured with coordinated overcurrent curves to trip only for faults downstream from its location with respect to the connected substation source.

Fig. 1. *(Permanent Fault on line Segment D)*



The sequence of events is as follows:

A. Device P5 detects a fault on line segment D.

B. The first fast shot coordinated overcurrent function in P5 times out and trips its recloser. (This device is set to operate faster than the substation controller P6).

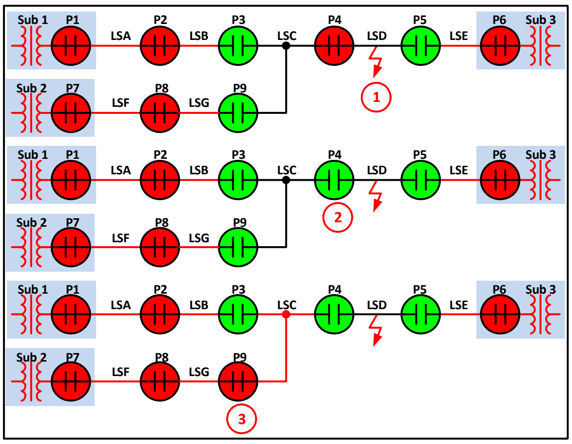
C. Device P5's auto-reclose function's first fast dead time will time out, causing the recloser to close back onto the faulted line segment to determine if the fault was temporary in nature.

D. Device P5 will detect that a fault is still present. The second shot coordinated overcurrent function in P5 times out and again trips its recloser.

E. Device P5's auto-reclose function's second slow dead time will time out and close the recloser back onto the faulted line segment to again check if the fault was temporary in nature.

F. Device P5 will detect that a fault is still present in the line segment. The selected third shot coordinated overcurrent function in P5 times out and again trips its recloser. (Note that device P5's settings are coordinated to trip faster than the substation reclosers, thus providing time for lateral line fuses to blow for faults beyond the fuse locations and thereby activate the lockout state).

Fig. 2. *(Post Protection Automation Actions)*



Post protection actions are indicated in Fig.2 and the steps are described in the following steps.

A. On reception of the Lockout state from device P5, the automation system will be triggered to act. The first action for this system will be to determine the location of the fault. This is accomplished by looking at the fault flag information provided by the protection devices or information supplied by fault sensors.

B. The fault location is determined to be between P4 and P5 on line segment D. The automation system issues an open command to Recloser P4. This completes the fault isolation actions.

C. The last step is to restore service to Line segment C. The automation system will close the normally open recloser P9.

The automation system must now adapt the protection settings on all affected devices to accommodate the new system topology.

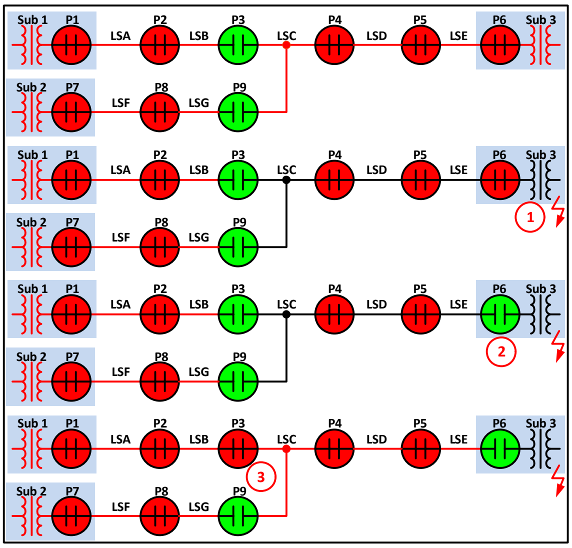
Line section C, that is downstream from the affected line section D, could constitute hundreds of consumers.

During the reclose cycles, these consumers are exposed to all protection interruptions in addition to the time it takes to locate the faults, isolate the line section, and finally close the recloser to provide an alternative power source.

The actions could take minutes or hours depending on the remote access time to control the reclosers in the system.

Protection coordination can also be challenged in this system if a source transfer action was executed by the automation system as depicted in Fig.3.

Fig. 3. *(Automatic Transfer Actions)*



A. In this example the Substation 3 source is interrupted.

B. The automation system detects the loss of source and opens recloser P6 in Substation 3.

C. The system then closes recloser P3 to provide power to line segments C, D and E.

The protection devices P1 through P5 must then be adapted to coordinate for faults on all five line segments.

This is typically extremely difficult to achieve on distribution systems due to the impact of fuse selections, loading and system impedances.

To overcome possible coordination issues caused by automation actions KUB decided to look at a system with a different approach to the conventional protection methods.

III. Different Approach to Feeder System Protection

The protection and automation systems must be closely coordinated in actions for both protection and automation functions to operate effectively.

KUB selected a system with a different approach is to eliminate the complexity of adapting the coordinated overcurrent settings on devices when topology changes are executed by the automation system.

To make this possible, the protection and automation actions must be executed synchronously.

Most digital protection devices have powerful logic programming capabilities and therefore it is possible to move the automation functions to the protection devices.

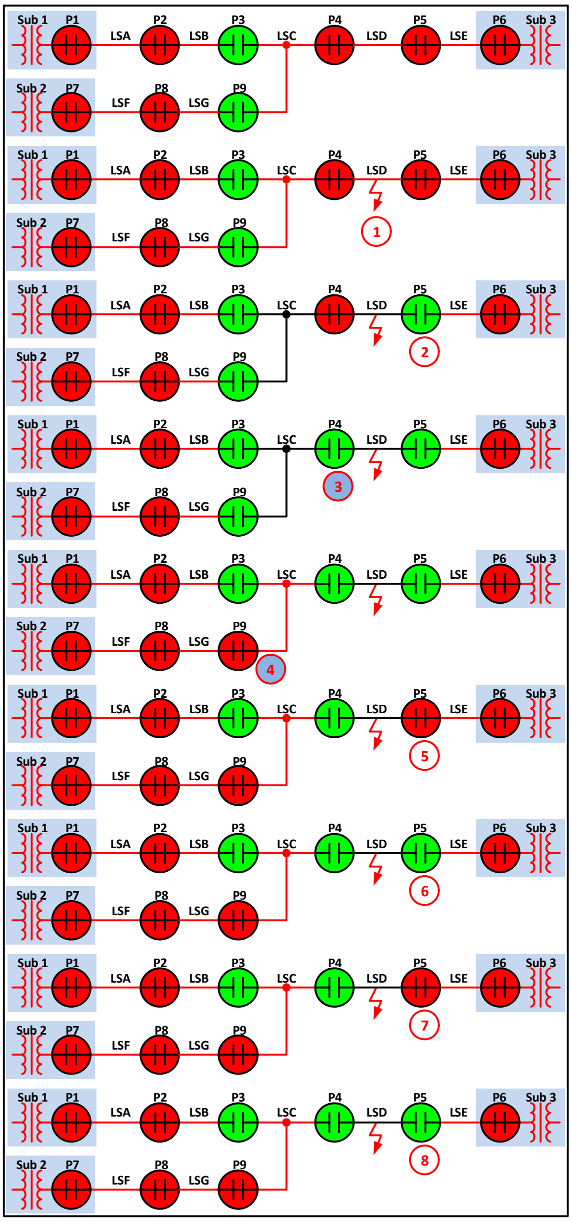
By contrast, it is not possible to move the protection functions to a central automation system server due to the latencies associated with communication infrastructure, processing time of the server and reliability concerns.

An added advantage that can be gained by this type of decentralized system is the speed of operation of the protection and automation system.

The decentralized system KUB considered, adapted a protection system, to incorporate all the feeder automation actions, this greatly improves the combined system performance as well as maximize the reliability by exposing less of the system to protection and automation operational interruptions.

Considering the same example, the selected system protects and automates in the following steps as indicated in Fig. 4.

Fig. 4. *(Synchronized protection and automation actions)*



A. Devices P5 and P4 detect and locate the fault in line section D using current jump differential protection.
B. Device P5's controller trips the recloser to isolate the fault.
C. Device P4's controller opens its recloser to isolate the faulted line section. (This is an automation action in the first example).

D. Device P9's controller now closes its open recloser to energize line section C. This is also an automation action.
E. The auto reclose on device P5 is then released to do a first reclose attempt. (Note: If the fault was temporary in nature this would be the last action and all line sections would have power. As a result, the open point would just have moved from P9 to P4).
F. Device P5's Controller will detect that the fault is still present when it closes and activates its slow over current curve. (The slow curve will give the downstream lateral fuses time to blow if required). Note: This active curve on P5 needs only to be coordinated with the substation recloser and the fuses. During the reclose cycles only the device reclosing and the first devices connected to the system sources are active.
G. The P5 controller will then close again after the second dead time.
H. Finally, the P5 controller will still detect the fault, trip, and activate the lock out state.

These actions have a tremendous benefit for the consumers connected to line section C. They will only see a short interruption and will not be exposed to all the protection interruptions and reclose actions as in the previous example.

To get this approach to work in the example topology, it is essential that the field and substation devices communicate and share information in real time. IEC61850 "GOOSE" messages are used by the selected system to share information.

Though a direct fiber connection between devices is preferable, it is not always possible to have dedicated fiber available as the communication platform for automation systems to perform protection and automation actions.

For KUB it was just not economically feasible to run fiber to all reclosers that would form part of all automated feeders in the distribution grid. Therefore, it was required that "GOOSE" be able to function over wireless radio systems. KUB investigated most of the modern IP based radio systems (Wi-Fi, WiMAX, Cellular 4G) to support Multicast traffic such as "GOOSE".

What makes "GOOSE" ideal for this application over wireless communication?

- It is a small packet protocol, ideal for wireless systems.
- Analog or binary information can be shared for processing by the protection and automation controllers.
- Data traffic can be managed using set retransmission time intervals of the "GOOSE" packets.
- The "GOOSE" packets contain quality information. Therefore, devices can filter and discard "GOOSE" packets with incorrect quality information.
- An additional layer of security is added to normal IT cyber security requirements.

The next requirement for KUB was the ability to locate the fault accurately and immediately on each automated line segment. The system that was selected use differential protection methodology to accomplish this, the feeder is broken into line segments where currents are measured at either end and compared through peer to peer "GOOSE" communication to locate a fault.

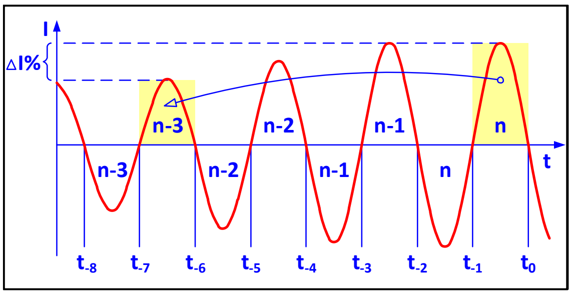
IV. Jump Differential Protection

The Jump Differential concept was developed to gain the benefits of a differential protection function on distribution feeders using wireless communication systems. The function provides not only the selectivity, but also the security and speed of operation typically expected from a conventional differential protection relay. To accomplish this, each device includes two differential functions. This method makes it possible for each device in the field to communicate with multiple upstream and downstream devices, supporting two differential zones.

In contrast to a conventional line differential scheme, which typically requires the comparison of real time phase currents from both sides of the protected zone, the jump differential algorithm converts magnitude changes in the phase currents to logical signals called "Positive jump" and "Negative jump". These signals are transmitted through the communication network as binary signals to the upstream and downstream devices and ideal for application in wireless communication systems.

The jump differential algorithm utilizes the measured currents flowing through the primary switch unit current transformers or sensors and compares the current measurement of the measured half cycle area to the memorized area of 3 cycles previous as depicted in Fig.5.

Fig. 5. *(Current Jump Detector)*

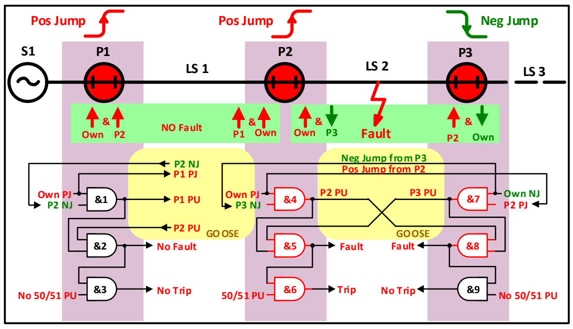


If the difference is greater than a pre-defined percentage threshold, the device generates a positive or negative jump within a half cycle. The "Positive Jump" generates a positive jump "GOOSE" message that is transmitted to the other line ends as depicted in figure 6. Conversely, a sudden decrease in current causes the device to generate a "Negative Jump", and triggering its own "GOOSE" message.

In the Fig.6 example, there is a fault on the line section between devices P2 and P3. The fault current will cause P1 and P2 to generate "Positive Jump" signals (P1 PJ, P2 PJ). Device P3 will notice the sudden decrease in current and then issue the "Negative Jump" (P3 NJ). The jump differential logic evaluates its own signals as well as information coming from the opposite line end. The pickup equation is fulfilled if a device detects the difference, having its own "Positive Jump" and the "Negative Jump" "GOOSE" from the neighboring side. In our example, device P1 will not issue the pickup because it has its own "Positive Jump" and "Positive Jump" "GOOSE" from P2 (none of the AND Gates 1, 2, 3 will be true). Device P2 will have its own "Positive Jump" and "Negative Jump" coming from P3. The AND Gate 4 will generate a pickup signal P2 PU and transmit it to P3. In turn, device P3 will also detect the difference between its own "Negative Jump" and a "Positive Jump" received from P2. The AND Gate 7 will fulfill and reply to P2, with a pickup signal P3 PU confirming the fault in the line segment. When received, this signal will fulfill the "Fault" equation at P2, formed by AND Gate 5. The last stage requires an overcurrent release set to a minimum fault current level. This ensures that the function will not operate for jumps caused by switching actions or sudden load changes. With a confirmation signal from the overcurrent element, the AND Gate 6 will become true and open the recloser P2 to isolate the fault.

When devices P1 and P2 received positive jumps from either end, these "Positive jump" signals provide in effect a restraint to the algorithm for line section LS1.

Fig. 6. *(Jump Differential Protection)*



Other considerations that are included in the differential protection or fault location algorithm to account for possible abnormal scenarios:

- If no negative current jump is possible, e.g. one line end is an open point, the function relies on a permissive signal that replaces the negative jump signal. The function will thus always work with fresh signals from both line ends to determine the fault location.
- The function will be blocked if 2nd harmonic inrush is detected or if there is a communication failure between the devices.
- The function includes dead end trip logic. Thus it can issue a trip for a fault that is on the lateral radial feeder by opening the lateral feeder's recloser. This logic applies when an upstream device does not have another device downstream to compare information with.
- To counter act the effects of large active loads, e.g. motors, current reversal logic

blocks the issuance of possible incorrect positive jumps.

For its operation, the differential algorithm requires only two settings to determine the positive and negative jumps, which are typically set to 15%.

This was an important consideration for KUB to simplify the protection settings especially for a large-scale deployment.

V. JUMP DIFFERENTIAL PROTECTION PERFORMANCE

The speed of operation of this function is influenced by the communication latency and can be described by the following formula:

$$T_{Trip} = (T_{JD}+T_{C1}+T_{L}+T_{C2})+T_{D};$$

Where:

- T_{Trip}- trip time;
- T_{JD}- positive or negative jump detection time (avg. 15 ms);
- T_{C1}- communication latency in the first data exchange;
- T_{L}- logic time (avg. 15 ms);
- T_{C2}- communication latency in the second data exchange;
- T_{D}- additional set time delay (if required)

Considering these parameters, the expected minimum operating time may vary for different communication systems as tested by the vendor:

Table 1. *(Jump Differential Performance)*

Communication System	**Peer-to-peer latency**	**Jump Differential minimum Operating time**
Fiber Optics	4ms	38ms
WiMAX/Wi-Fi	35ms	100ms
4G/LTE Cellular	100ms-150ms	230ms-330ms

KUB looked at number of installed systems where this function was deployed by the vendor using WiMAX communication systems.

The COMTRADE fault record from an actual operation is shown in figure 7.

The device detected a "Positive Jump" (marker A) 8 ms after phase C current reached the fault magnitude.

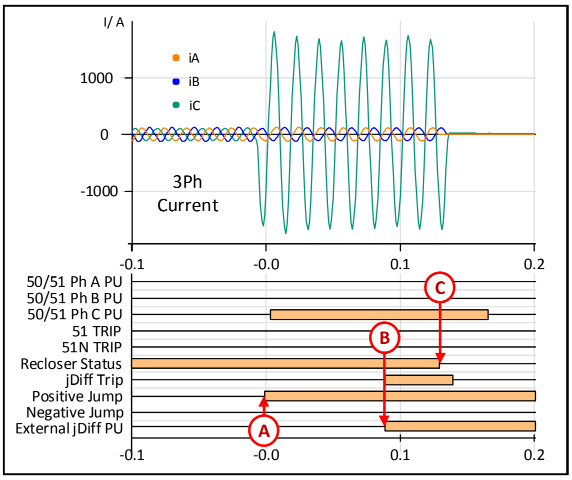


Figure 7.

This signal was sent to the downstream device as a "GOOSE" message over the WiMAX wireless communication system. The device on the other side of the line section did not generate a Positive Jump because fault current was not flowing through its CTs. Due to the lightly loaded line section, the downstream device did not experience the Negative Jump, but replied with the pickup signal after receiving a "Positive Jump" from the upstream controller. Once received, the pickup signal from the downstream device (marker B) latched the Fault condition and issued a trip. The recloser physically opened in 30 ms (marker C). The fault condition was broadcast to the rest of the system. In this example the trip signal was issued in less than 100 ms, so it illustrates that the jDiff algorithm requires peer to peer latency of no more than 35 ms to trip within this timeframe.

VI. KUB'S ADAPTATIONS

In the KUB deployment the substation feeder breaker could not be included automation and protection system. The differential function concept could thus not coordinate with the substation breaker.

In addition, the system had to function on cellular communication system that required important adaptations.

The latency of 4G could in some instances not be fast enough to support the jump differential function performance as discussed. The extended operating time caused by irregular longer communication latencies could not guarantee that the differential function could detect the faulted line segment before the substation protection relay would trip on an overcurrent for a high-current fault causing an uncoordinated tripping scenario. The first action to solve this problem was to speed up the differential function by adapting the logic and employ only one data exchange between devices from opposite line ends, minimizing the impact of longer latencies in cellular communication systems. The function will immediately generate the echo-pickup signal from the downstream device if it detected a voltage sag and did not detect its own Positive Current Jump.

The upstream device, on receipt of this echo-pickup along with its own positive jump can detect the fault within the differential zone of protection. In addition, if a downstream device sees the Positive Jump, it would not reply with an echo-pickup to the upstream device indicating that the fault is downstream from it.

This approach to reduce communication exchanges between devices was tested successfully, but the varying communication latency on the cellular network could still cause too large of a delay in data exchange. After a series of tests performed by KUB, a new approach was adopted that minimized the impact of the possible unwanted extended communication latency exchanges. This new approach is to allow the head-end feeder device to operate on overcurrent for any downstream fault.

This first, possibly non-selective operation, will allow differential function to determine the fault zone location during the dead time. By the time the head-end device recloses, the fault location is determined, and an overcurrent element is activated on the first device upstream to the fault.

KUB effectively used the differential function to locate faults and unblock overcurrent elements to perform coordinated tripping.

The following KUB rules were implemented in the system logic to achieve this functionality:

Rule 1 - The head-end device shall have its overcurrent element (TCC) active if fault location is not provided by the differential function, or during a possible communication failure. This condition is required to provide conventional overcurrent protection until the faulted zone is determined.

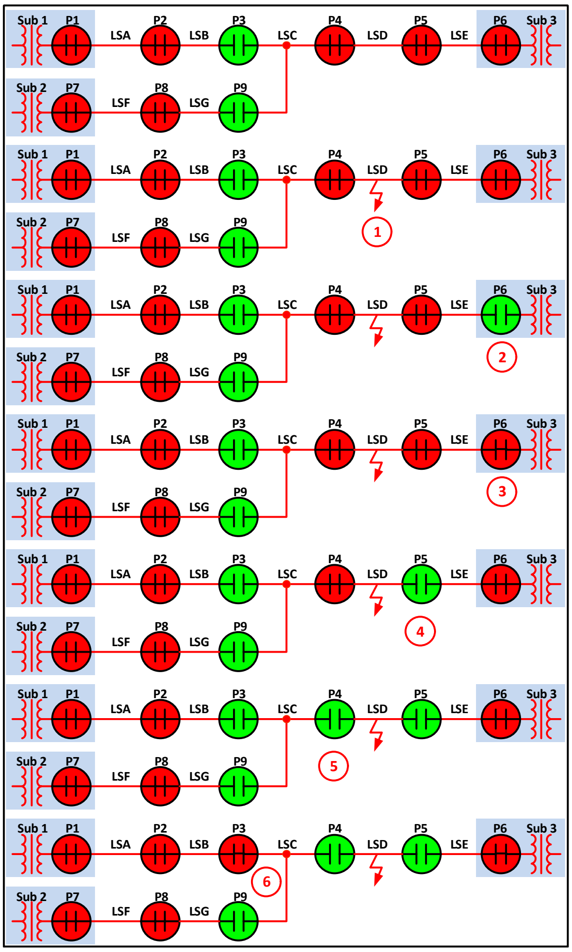
Rule 2 - The head-end device shall have its overcurrent element immediately blocked if a fault location is provided by the differential algorithm and the fault location is outside of this device's differential zone.

Rule 3 - All other system devices have their overcurrent elements blocked. The following action takes place during the first shot's reclose dead-time. The device on which the differential function locates the faulted zone will unblock its overcurrent element.

Rule 4 - All devices shall not issue positive jumps if jump was caused by the reclose action from the upstream device.

These rules will govern the system operations in the following sequence depicted in Fig.8.

Fig. 8. *(System Operations for a slow communication latency)*



In this example the substation relays at P1, P6 and P7 forms part of the protection and automation system.

A. A fault occurs on line section D. Devices P6 and P5 will detect the fault current and issue the positive jump. The fault location is not yet known to the system. The overcurrent element at P6 will pick-up in accordance with **Rule 1**.
B. Device P6 will timeout and trip from its TCC as the fault location is not yet determined due to the slow communication latency in this example.
C. Device P6 will reclose very fast after the first shot dead time. By this time the jump differential function logic will have received "GOOSE" messages from the other devices and determined the fault location. If the fault is not on line section E, device P6 will automatically block its overcurrent element (TCC) in accordance with **Rule 2**.
D. Device P5 will unblock its overcurrent element, time out and trip according to the Rule 3.
E. Device P4 will open to isolate the faulted line section;
F. Device P3 will close to energize unfaulted line section C.
G. Device P5 will perform the set number of auto reclose attempts.

In the shown sequence of events, all devices in this system utilize identical overcurrent protection settings.

A. In cases where fault location determination time happens to be shorter than required clearing time of head-end device, the system device P6 in the above example would not have operated. This can happen whenever fault current is small enough for its associated TCC time to exceed fault location time or if latency is short enough to permit fault determination faster than clearing time requirements for the particular fault current. In such cases, the following will occur. Device P5 will unblock its overcurrent element, time out and trip according to the **Rule 3**.
B. Device P4 will open to isolate the faulted line section;
C. Device P3 will close to energize unfaulted line segment C.
D. Device P5 will perform the set number of auto reclose attempts.

In this adaptation the differential function controls an overcurrent blocking scheme. Overcurrent blocking and unblocking is done by the accurate and selective fault location provided by the jump differential function. The overcurrent blocking and unblocking is not performed based on the status of the systems primary switches making the system protection logic very simple and not affected topology changes.

If the differential function can locate the fault fast enough, it can be set to either trip or optionally to release an over current element. This overcurrent element can be set to coordinate with lateral fuses or reclosers.

For KUB the substation breaker protection is typically not included in the feeder automation system. The system needs to coordinate with the substation breaker. For this the application the system was set to operate as described below:

- Apply one set of coordinated overcurrent curves with the substation relays on all head-end devices and another set on the downstream units.
- All downstream devices shall be coordinated with the downstream lateral fuses, the upstream head-end device and the substation breaker to form 3 coordinated zones.
- The differential algorithm will unblock the overcurrent element on the device connected to the faulted line section or zone.
- The overcurrent element on the head-end devices can always be active as a backup regardless of the differential actions.

Only in the rare instances where the communication exchange is slow, could there possibly be one uncoordinated trip. Mis-coordination correction will then be performed before the first reclose cycle of the device that tripped.

KUB did not experience any instance as described above in the automated feeders deployed in the field of during testing and commissioning of the systems.

VII. Overcurrent Protection Coordination Strategy

For application of the new automation system to improve feeder reliability, the KUB approach was to begin using the new automation system in lieu of stand-alone three-phase reclosers as was previously used to segment certain feeder trunklines and major branch circuits. As referenced herein, the feeder trunk lines are circuits that interconnect two or more feeders via open switchable devices for the purpose of recovering the entire load of a distribution feeder breaker should it ever be interrupted. Major branch circuits, as referenced herein, are tap circuits with load too large for single-phase protective devices but not adequate to carry the load of the entire feeder and thus are connected radially to one or more feeder trunklines without intent to carry power through the branch from one feeder to another.

KUB desired to maximize compatibility with its existing protection systems while obtaining the benefits of the new automation system. Standard protection settings already had been established for distribution feeder breakers and existing single-phase lateral taps such as tap fuses and single-phase reclosers.

The ground overcurrent protection coordination time interval between standardized existing single-phase lateral devices and standardized distribution feeder breakers was enough to fit about two time-overcurrent curves without affecting its ability to carry maximum allowed phase unbalance current.

In order to permit independent automation between feeder trunklines and major branch circuits, KUB added the requirement that the automation system must use no more than one phase and ground coordination curve per each entire automation team of reclosers.

This allowed standardized phase and ground time-overcurrent protection settings of the new feeder trunkline automation teams to coordinate slightly faster than existing standardized distribution feeder breakers and slightly slower than the new standardized major circuit automation teams, which in turn coordinated slightly slower than standard existing single-phase lateral protective devices.

Since some new automation devices needed to be placed near feeder sources, instantaneous overcurrent protection was coordinated by number of reclose cycles alone rather than by protection reach; i.e., coordination by lockout.

Thus, for very high current faults that require faster interruption to avoid undesired widespread voltage sags or equipment damage, the automation system permits assignment of designated default tripping device to any member of the team that can trip for protection prior to determining exact location of the fault.

KUB set automation team device time-overcurrent phase protection to disc-emulation reset to coordinate with its standardized feeder protection and similarly set ground protection to instantaneous reset to coordinate better with existing ground protection devices.

Consequently, some legacy feeder ground protective devices had to be upgraded to instantaneous reset devices as has been common practice when adding three-phase reclosers to feeder circuits. Reclose interval reset times were adjusted accordingly to continue to permit lockout even for low level faults.

The topology of complex distribution feeder interconnections includes feeder trunkline teams between feeders and major branch circuit teams between sections of different feeders. Laterals are connected to both trunklines and major branch circuits. Protection for primary service to very large customers is typically accomplished with settings similar to or compatible with major branch circuits.

For convenience, the same standardized settings are applied to each member of all automation teams with distinction between feeder and major branch protection settings being accomplished by setting groups.

Group A was used for the standardized feeder trunkline automation protection settings and Group B was used for the standardized branch circuit automation protection settings.

The selection of which setting group that is activated for a device on a team or stand-alone application is made at design time and easily implemented and set during commissioning.

The end results are:

A. Except for laterals very near the source, most lateral faults can be cleared by single-phase lateral devices without ever operating team or feeder devices.
B. Low to medium current faults on main lines of major branch circuits or feeder trunk lines can be cleared and reclosed by the nearest upstream device since fault location is determined by team prior to first required interruption for this level of fault.

High-current faults are first interrupted by the designated default tripping team device and then isolated and reclosed by the nearest upstream team member device after fault location is determined by team. The interruptions for such high-current faults are sometimes by instantaneous functions.

VIII. Communication System Challenges

KUB decided to use cellular communication to support for the large-scale feeder automation deployment project.

KUB investigated many communication system possibilities. The decision was finally made to use cellular communication to support the feeder automation and protection system.

The two major reasons for the decision was the **availability** and **deploy ability** of cellular in the KUB area. The hilly topography with tall trees made it very challenging and expensive to deploy an own highspeed communication system.

KUB acquired a private cellular network from a major cellular provider. The private network would only be used for the distribution feeder automation project's field devices as indicated in Fig. 9.

It is important to note that a private cellular network has no connection to the public cellular networks or the internet. No unsolicited traffic can enter this network.

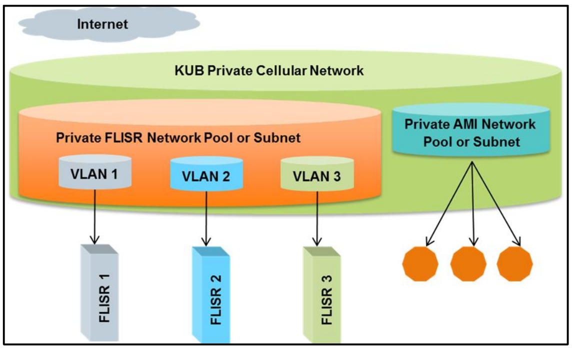


Fig. 9. *(Private cellular network architecture)*

KUB acquired Machine to Machine (M2M) data plans for the cellular modems to be used to support the systems.

The decentralized automation system KUB selected required high speed peer-to-peer communication between all devices. In the IEC 61850-8-1 standard, one of the messages associated with the GSE services are the Generic Object Oriented Substation Event ("GOOSE") messages that allow for the broadcast of multicast messages across the Local Area Network (LAN). It was designed to share data between protection points through an Ethernet network on a peer to peer basis, and is the standard communication protocol for protection applications, with each device periodically multicasting the "GOOSE" messages to the other devices. Note, if a cellular network is used, the cell modems are required to be setup for point to multipoint communications).

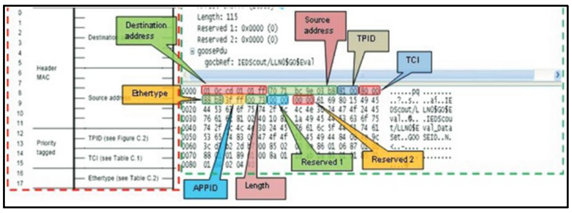
IX. GOOSE Structure and Settings

Fig. 10 shows the "GOOSE" message from a Wireshark trace. Some important components in a "GOOSE" structure include:

- Preamble and start of the frame which is done at the hardware level and not shown in the figure
- Fixed 6 byte size destination and source multicast addresses
- Priority tagging to separate time critical and high priority traffic
- The 802.1Q VLAN (Virtual Local Area Network) is 4 bytes in size and consists of
    - TPID – Tag Protocol Identifier
    - TCI – Tag Control Information
    - Ethertype (0x88b8 for "GOOSE")

- APPID identifies "GOOSE" messages based on their application and is 2 bytes in size.

Fig. 10. *(GOOSE Message Structure)*



For the distribution feeder protection and automation application, large numbers of "GOOSE" messages are communicated between all devices in a system. The "GOOSE" structure and settings are adapted for this solution making it possible to work on wireless IP based communication networks such as the cellular system. Some of the key settings include:

Limiting to 3 "GOOSE" application types:

- Control – Includes "GOOSE" messages related to system modes, remote control, measurements etc.
- Status – Includes "GOOSE" messages related to the open/close feedback from all the devices in the system.
- Protection – Includes time critical differential function "GOOSE" messages between the devices in the system.

Setting parameters of each "GOOSE" application

- VLAN – Same Layer II VLAN setting for all the "GOOSE" applications
- Max time setting for each application set to the maximum. In normal conditions, the duration for repetitive "GOOSE" messages (1.5 times the Max time setting) so that the data consumption is minimal at the cell modems.
- Min time setting is customized for each "GOOSE" application based on the importance. Protection and status applications have sensitive Min time setting compared to the control application
- Customized Layer II VLAN priority for each "GOOSE" application. Highest priority is given to Protection and Status applications compared to the control application. These measures guaranteed successful delivery of the "GOOSE" messages with dynamically changing communication network

X. VIRTUAL LAN

Every autonomous feeder protection and automation system, of between 4 to 15 field devices was assigned a unique VLANs as indicated in figure 10.

A virtual LAN (VLAN) is any broadcast domain that is partitioned and isolated in a communication network at the data link layer (OSI layer 2). The Layer II VLAN parameter is the key differentiation feature for an IEC 61850 based "GOOSE" message. It is crucial to have a unique VLAN assigned to each feeder automation system. This VLAN assignment avoids any duplicates and/or collisions of Layer II "GOOSE" messages between devices from 2 different systems. In the KUB system with Layer 3 cellular data communications, cell modems are configured with L2TPV3 (Layer 2 Tunneling protocol version 3) which uses the same layer II VLAN assigned to the "GOOSE" messages originating from the controller. Some of the important features of Layer II VLAN include:

- Enhance Network Security – All the "GOOSE" messages with a unique VLAN tag are broadcast within the networks associated on the same VLAN. Each layer II VLAN can be assigned with a specific layer III IP address (tunneling) to pass layer II traffic over a layer III IP network over a secured communication path (tunnel)
- Network Management – At the recipient device in a multi-device network, VLANs provide networking devices (routers) with a capability to easily filter the broadcast traffic based on their VLAN
- Mitigate Network Congestion – VLANs over layer III provide separate communication paths (tunnels) which are peer to peer and have their own tunnel parameters, thus avoiding any collisions.
- The tunneling was a very important aspect for KUB to ensure field devices are linked to each other by these virtual wires. This greatly eliminates the possible generation of duplicate "GOOSE" form other feeder systems or "GOOSE" test equipment.

XI. "GOOSE" over Cellular to Support Protection Applications

Transmission of many "GOOSE" messages over a cellular network poses several challenges including latency, reliability, data consumption etc.

XII. Layer 2 tunneling over Layer 3 IP network (L2TPV3 tunneling)

L2TPV3 (Layer 2 Tunneling protocol version 3) VLAN tunnels are configured between all modems to communicate IEC61850 "GOOSE" messages.

To make deployment easy all Cellular modems was preconfigured to support tunnels for 20 field devices. Only a few settings as indicated below are required in the configuration of each modem.

The tunnel configuration settings include:

- VLAN number – Same VLAN number associated with the "GOOSE" messages originating from the respective device
- Session parameters – Identical session parameters on either side of each tunnel
- Local and remote ports – Unique local and remote ports associated with each tunnel
- Local and remote static IP addresses – Local and remote SIM card static IP's assigned by the cellular provider

XIII. IPsec Security

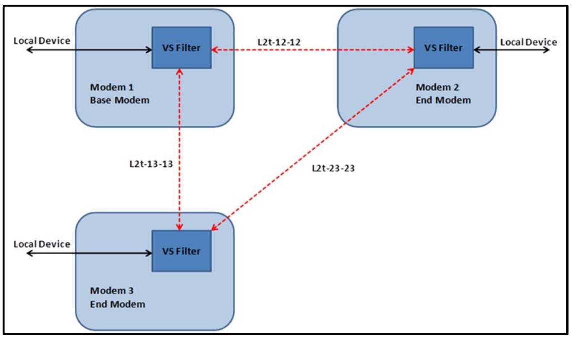
IPsec is one of the key security features implemented in the cellular modem to provide immunity to cyber-attacks. IPsec protects each tunnel connecting all the devices form possible penetration. For the KUB system applications, IPsec adds an additional layer of security over the existing L2TPV3 tunnels. IPsec is configured to encrypt/decrypt any data entering/leaving the L2TPV3 tunnel respectively. IPsec features include:

- Data Encryption (Data Confidentiality) – Inbuilt 256 Bit AES security algorithms are used to encrypt any data communicated over the cellular network.
- Modems verify pre-shared keys (Unique key can be assigned for each link) before sending/receiving any data.

XIV. Virtual Switch Filter

The virtual switch filter was developed to ensure no communication loops was created on cellular system. Without such a filter the cellular system would be flooded with duplicate packets form all devices in the system.

Fig. 11. *(Virtual Switch Filter)*



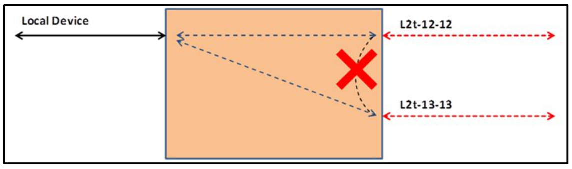
Virtual switch filter configuration:

- Identical virtual switch configuration in all the devices
- All modems have pre-configured L2TPV3 VLAN tunnels to all the other modems in the system
- Inter tunnel traffic (traffic between the VLAN tunnels portion of a virtual switch) is not allowed (concept shown in Fig. 11)

Advantages of a virtual switch filter include

- Avoiding single point of failure.
- Similar latency between all the devices due to the peer to peer communication structure.
- Easier to program and manage since all the modems have identical tunnel settings.
- No special tunnel management server required that could add to the GOOSE latency.

Fig. 12. *(End to End Communication flow)*



The end to end communication flow between 2 controllers over a cellular network can be illustrated as follows:

- Layer II VLAN tagged IEC 61850 based "GOOSE" messages originate from one controller and enter the cell modem on a designated VLAN port
- The virtual switch acts as an unmanaged switch to bridge layer II VLAN traffic with L2TPV3 tunnels associated with same VLAN
- The static IP address assigned to the L2TPV3 tunnel adds an IP header to all the layer II data entering the tunnel
- IPsec encrypts all the data entering the tunnel with the selected AEC security algorithms and also adds a pre-shared key
- At the receiving device, the pre-shared key authentication is done by the IPsec at the recipient modem
- On a successful pre-shared key exchange, data is decrypted
- The static IP header is detached from the data
- The virtual switch bridges this data to the VLAN specified port at the other modem where the recipient controller is connected

XV. New Testing Methods

During the development of the differential algorithm, the inventors performed a series of tests with RTDS equipment to verify reliability and performance of this protection function.

The systematic approach was chosen whereby the distribution protection and automation project with 4 to 15 devices was first configured in the lab environment utilizing the cellular communication system for a feeder project. Devices can then be connected to either real primary switchgear (if available) or programmable logical controllers simulating the switchgear response.

During the lab testing, the distribution automation application is tested as a digital IEC61850 system including cellular communication. This includes simultaneous injection of all controllers with voltages and currents according to the normal, abnormal and fault scenarios. System responses to these conditions are recorded and analyzed to ensure correct and reliable operation. The communication system is also proven to support the application.

In order to perform efficient and effective testing, several testing tools and software packages were considered.

A conventional testing method that involves testing software with an iterative approach, driving the multiple injection sets through a series of automatic steps. This was successfully implemented and tested on a live feeder system with 7 devices in the field. This approach, however, required an individual test set for each location in the field or in the lab.

Many systems at KUB can easily exceed 10 devices in a single feeder system. If the application requires more than 8-10 reclosers in a mesh connected feeder system, it becomes challenging and very costly to provide current and voltage channels for every protection point.

Each system is subjected to over 300 tests to ensure correct coordination and automation sequence execution.

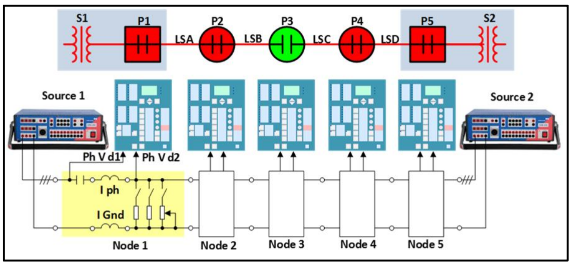
To overcome the requirements, it was decided to develop a new testing approach utilizing a secondary injection analog test system. This system consists of testing nodes connected according to the feeder topology as shown in Fig. 13.

A. *Hybrid Digital Analog Test System*

In this system, each node includes a three-phase circuit with a set of resistors, switches and an auxiliary 3 pole relay. This network of test nodes is fed by voltage injection sets. Current flowing through each test node is directly measured by the automation controller, which also receives 3 phase secondary voltage from both sides of the breaker relay contacts. In a normal scenario the variable resistors can be set to provide a simulation of the load flow current for each test node.

A fault scenario is triggered by switching on the fault resistors in individual or all three phases. The fault current is sensed by all upstream devices so they can react to the fault event. The control commands from the controllers as well as statuses of the switchgear can be monitored by the test sets through the binary inputs.

Fig. 13. *(Analogue Test System)*



This approach allows testing of system logic of large distribution automation and protection applications. After the system test is complete, the pickup levels of each device can be tested individually utilizing a conventional calibration test approach.

XVI. Conclusion

The system described in this article was originally developed using IEC61850 as the standard from the outset. This made it possible to ultimately create high speed protection and automated control system outside the substation fence. The system provides reliable differential type protection over various wireless communication systems including cellular. This differential protection approach makes the protection system immune to feeder topology changes.

KUB adapted this system to make large scale deployment possible. The adaptation included the use of a differential type function for fault location that in turn controls an overcurrent blocking and unblocking scheme.

Although adapted to enable a modularized approach, the KUB solution requires only one new overcurrent standard setting curve to coordinate between substation feeder and the laterals or fuses. The added benefit is that it replaced the curve space already used for 3-phase reclosers so it did not require re-engineering the whole system again.

The new system supports all possible feeder topologies in open-loop or open-mesh connected feeder automation and protection systems. The system was deployed on a cellular communication network with varying peer to peer latencies. The protection and automation system are designed to tolerate the effect of expected variable communication latencies.

The systems deployed in the field have operated numerous times and no incorrect or strange operations have been detected or recorded.

Lastly, a new hybrid analog test solution was developed to provide a cost-effective test system to support the testing of large distribution protection and automation system applications consisting of many devices.

KUB successfully removed all obstacles that is typically associated with the large-scale deployment of distribution feeder automation and protection systems.

XVII. References

Papers:

1. New Implementation of Adaptive Protection on Automated Distribution Feeders; Kelvin Pettit, Andre Smit, Member, IEEE, Ernie Creech, and Alexandr Stinskiy, Ph.D

2. New Protection Method Deployed on Automated Distribution Feeders; Andre Smit, Alexandr Stinskiy, Suraj Chanda, Todd Houseknecht Siemens Industry, Inc. alexandr.stinskiy@siemens.com

Patents:

1. US Patent: US 2011/0144931 A1 Method and Apparatus for High-Speed Fault detection in distribution networks
2. US Patent: US 2013/0265680 A1 Systems, methods and apparatus for protecting power distribution feeder systems

PAC World Articles:

Modern IEC61850 based Distribution Feeder Automation Systems - Andre Smit, Dr. Alexandr Stinskiy, Suraj Chanda, Todd Houseknecht - Siemens Industry, Inc. Raleigh, NC, USA

Wireless Communication Systems Supporting IEC61850 Applications - Andre Smit & Suraj Chanda - Siemens Industry, Inc. Raleigh, NC, USA Terry Fix - Dominion Energy Richmond, VA, USA

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