Case Study: Inglewood Distribution Automation

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***Abstract* – One application of distribution automation (DA) is the use of automated software to reconfigure the distribution system after protective devices have cleared and isolated a fault. The software takes in fault data and device status from the feeder breaker relays, reclosers, and other smart switching devices on multiple feeders. Using this information, the distribution system is typically restored in a different protection configuration than the initial system.**

This paper goes into the challenges encountered and possible solutions in dealing with multiple feeder sources in a radially fed distribution system. These challenges include maintaining protection standards and margins, load limits, protection setting groups, and utilizing aging infrastructure and relays in automation schemes.

DA solutions often propose proprietary technology and standalone devices in implementing the automation schemes. This specific case study focuses on integrating the automation software platform into the existing infrastructure of the utility. The types of relays integrated include electromechanical, first generation microprocessor based relays, and modern day microprocessor based relays.

Proprietary distribution automation schemes can have higher momentary average interruption frequency index (MAIFI) numbers as a result of poor system protection integration into the automation design. This paper focuses on developing methods to reduce unnecessary momentary outages to customers during an automation scheme restoration. By integrating proper system protection practices and principles into distribution automation unnecessary outages to the customer can be reduced.

This paper outlines a possible solution of using a "non-fault tripping" setting group on a recloser controller to maintain coordination with existing protective devices. With proper initiation by the automation software for specific radial feeders, this setting group will still allow upstream device coordination with existing downstream and upstream devices. Additionally, the protective device can still send fault target information back to the automation software in this group. When normally fed this recloser controller can be utilized as a protective device by switching the setting group back to its normal state. This is a more cost effective design than allowing device miscoordination and increasing MAIFI as a result of poor system protection integration into DA.

I. Introduction

In 2015, Puget Sound Energy (PSE) formed a small team tasked with selecting a distribution automation platform to incorporate into the existing radial feeder system. The fault location, isolation, and service restoration (FLISR) system was selected to reduce system average interruption duration index (SAIDI) times for problem circuits. The system selected used a centralized approach by controlling the automation through the energy management system (EMS) to the SCADA network. When enabled, the FLISR software acted through the EMS system to open and close the protective devices on the circuit restoring customers based on the fault location and real-time information sent. Figure 1 shows a basic diagram of the system implemented.

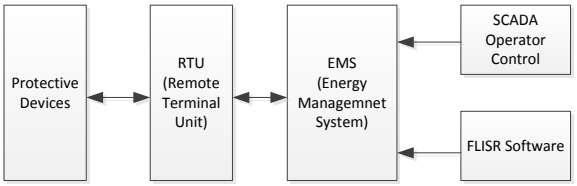

Figure 1 – Diagram of FLISR Setup

Over 5 years, each DA project was estimated to save on average 5,000 customer interruptions and 700,000 customer interruption minutes. The DA projects were chosen based on circuits with lower reliability numbers by the system planning team at PSE. Figure 2 shows one of the first installations at Inglewood substation. This is a typical radially fed distribution station. The substation consists of a 115kV/12.5kV Delta/Wye 25MVA transformer bank with a feeder tree consisting of four 12.5kV feeder breakers with 20kA interrupting capability. The feeder breakers are an older generation design with electromechanical relays. Puget Sound Energy has over 300 distribution substations of similar design. To support the amount of funds targeted at the DA projects each year, standard protection settings and project implementation documents were required.

The Inglewood DA scheme consisted of 7 different recloser controllers and 3 existing circuit breakers at 2 different substations. Some of the reclosers utilized in this project were near end of life and marked for replacement. New ones were installed in normal open (N.O.) positions, as shown in Figure 2. All recloser controllers installed were microprocessor based. The feeder breakers were not near end of life and were reused as part of this DA project. The circuit breakers utilized electromechanical relays for the feeder protection.

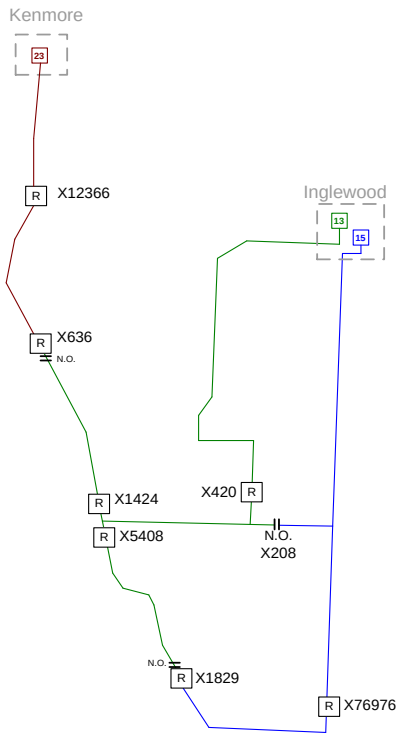

Figure 2 – Inglewood DA Scheme One Line

II. Maintaining Protection Standards

Standard utility practice on these types of radial distribution systems include 51P (overcurrent phase) and 51G (overcurrent ground). These protection curves are staggered to ensure by design that the furthest downstream protective device clears the fault. The margin between the protective devices is commonly referred to as the coordinating time interval (CTI). [1] PSE utilizes a "fuse blowing scheme" in which it allows the fuse to blow prior to opening the upstream recloser device. [4] After the recloser has initially opened, it is followed be a 10 second single shot reclose supervised by a hot source voltage. If the reclose is unsuccessful the recloser goes into lockout.

Distribution CTI's are commonly 0.25 to 0.3 seconds. [1] [2] Figure 3 below shows standard feeder curves stacked. As more devices are added in the circuit the margins are pushed closer to the lower limit of the fuse size which is fixed based on circuit loading. The upper limit remains fixed based on the substation transformer curves. The transformer protection curves must provide adequate protection for low side feeder bus faults while ensuring that the expected thermal and mechanical damages to the transformer are not exceeded.

As more protective devices are added to the circuit minimum CTI margins cannot be maintained and thus miscoordination will ultimately occur. The DA software restores the protective devices in abnormal radial feeds using multiple sectionalizing devices, in this case reclosers. A system that normally only had a few reclosers in series could now see up to 4-5 protective devices in series. PSE has a standard practice of not allowing installation of any reclosers where these CTI margins cannot be met.

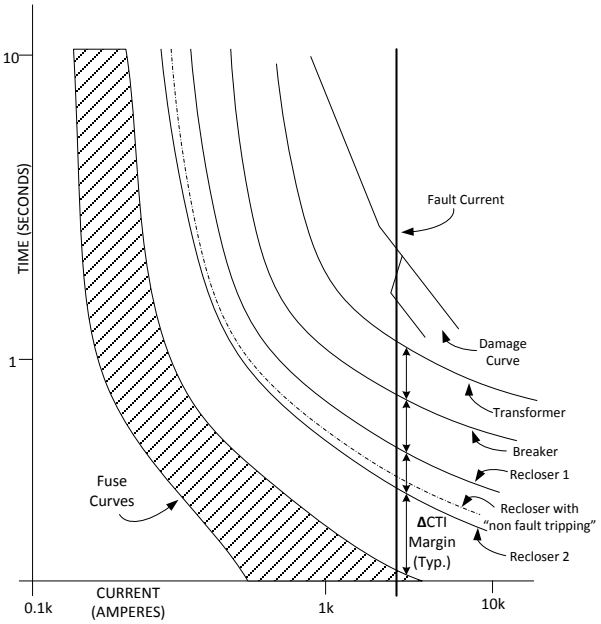

Figure 3 – Typical Feeder Protection Curves

To maintain CTI margins, some reclosers were set to a "non-fault tripping" setting group. These reclosers were programmed with the same overcurrent pickup levels as the upstream devices. With the exception of the overcurrent elements being removed the trip equation of the relay. This allowed the recloser controllers to send fault target information back to SCADA but not risk miscoordinating with the upstream devices. Hot line work switch (HLWS, 50P) tripping functionality was still maintained in this group for operational personnel use. The DA scheme is automatically disabled when HLWS on any protective device is enabled.

Miscoordination can also be resolved within the FLISR software itself. The software looks at the targets from both devices that opened and chooses the furthest one downstream. This is a weaker option due to the increased exposure to momentary outages. The reclosing cycle can also be hindered by miscoordination due to source voltage being lost on the downstream device. Figure 4 illustrates an example of this during a permanent fault.

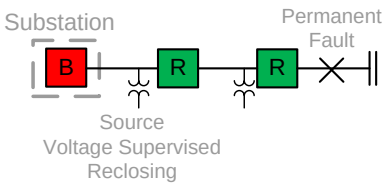

Figure 4 – Miscoordination with source voltage supervised reclosing

In this example the upstream recloser with hot source voltage attempts its single reclose shot first. If the fault is downstream of the second recloser the upstream recloser will successfully complete its reclose cycle. Once the line voltage becomes hot on the downstream recloser it will also attempt a single reclose shot. This will expose customers on both line segments to the permanent fault again.

By allowing a protective device to operate in the "non-fault tripping" setting group, proper device coordination with or without the automation scheme enabled is achieved. It also minimizes exposure to multiple recloses for the same fault. The design allows for normal reclosing operation for momentary faults, while still sectionalizing and restoring the system for permanent ones. This effectively turns the reclosers into a SCADA sectionalizing device when the DA scheme is in service and a fault target device when it is disabled.

III. Establishing System Protection Requirements and Implementation

During the project scoping, guidelines were developed to ensure that the each DA project could be completed efficiently and on budget. New recloser controllers and equipment were standardized to meet the demands of the DA system. Specific models of recloser controllers were deemed incompatible with the DA scheme if they were not able to meet specific requirements set forth in the protection requirements. The factors in deciding the replacement of the protective devices were:

- Age of Controller
- Ease to Program
- Ability for Voltage Sensing
- SCADA Capability

PSE has over 1,260 feeder breaker relay sets. 20% of these are first generation microprocessor relays. 10% are modern day microprocessor relays. The other 70% are electromechanical. Due to the vast majority of electromechanical relay sets still in use in PSE's system a method was needed to integrate them into the DA scheme. Substation feeder breakers are typically only replaced on an end of life schedule. The cost to replace these breakers is much higher than a standard recloser controller and/or mechanism.

The DA software monitors the fault target information coming back to EMS. It knows to sectionalize and restore the system based upon what fault target information is available. At minimum, it requires both the fault target information as well as an open status of the breaker. To compensate for the lack of an intelligent electronic device (IED) targets needed to be sent back from the electromechanical feeder breakers to EMS. Most of the substations already utilized an RTU that was capable of receiving high speed status back from hard wired contacts. A trip indication relay (TIR) was selected to be the proper solution due to its high speed pickup based on minimal current draw. Special considerations were taken to ensure that it didn't assert for instances where the HLWS was enabled. Trip shunt varistors also needed to be adjusted so enough current was available to pick up the TIR for magnetic actuated circuit breaker applications. These types of breaker mechanisms use a circuit board as a trip circuit input and have high impedance. Adjustments to shunt varistors were required to induce the more normal trip current values seen on standard mechanism feeder circuit breakers. Figure 5 shows a simplified diagram of a TIR in a trip circuit.

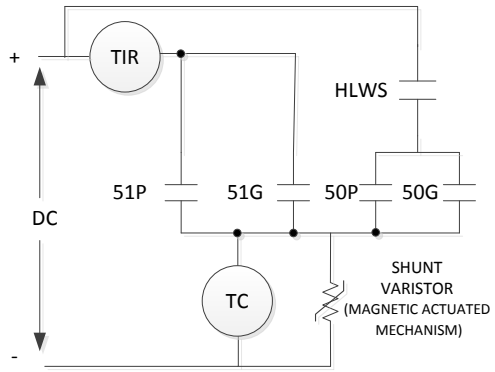

Figure 5 – Simplified DC schematic of trip indication relay implementation

The high speed contact output of the TIR directly connects to the RTU at the substation. This was used to send back fault target information and allow the DA system to starts the restoration process. This method saved additional time and money from having to retrofit the existing breakers with microprocessor based relays, when the breaker mechanisms were not near their expected end of life.

IV. Protection Setting Diagrams for Automated Switching

The DA software restores the circuit in different radial configurations based upon device loading information and software selected preferences. The software utilizes "protection profiles" to allow selection of setting group profiles to enable different setting groups on the reclosers depending on which circuit they are fed from in the scheme.

Given the amount of possible switching combinations, protection settings configuration needed to be documented. This would aid in testing the DA schemes and provide a reference to the operators during restoration operation if the system needs to be operated manually. The automatic switching diagram shows the following information:

- Setting group selection based on feeder source
- Load limits of each protective device

- Scheme anomalies
- Type of relays used
- One line diagram of system showing devices in individual FLISR scheme.

NAME	IED	LOAD LIMIT (A)	SETTING GROUP FOR RECONFIGURATION		
			KNM-23	ING-13	ING-15
KNM-23 X636	XXX	###	2	2	2
ING-13 X1424	XXX	###	1	1	1
ING-13 X5408	XXX	###	2	1	2
ING-15 X1829	XXX	###	2	2	2
ING-15 X420	XXX	###	2	1	2
ING-15 X76976	XXX	###	2	2	1
ING-13	EM	###	-	-	-
ING-15	EM	###	-	-	-
KNM-23	EM	###	-	-	-
SETTING GROUP 1 – RECLOSER WILL TRIP FOR FAULTS DOWNSTREAM SETTING GROUP 2 – RECLOSER WILL SIGNAL AND TARGET ONLY FOR FAULTS DOWNSTREAM					

Figure 6 – Example table for setting group reconfiguration

The load limit information was very important since PSE does not use a distribution management system (DMS). This information was typically linked to the feeder pickup levels, continuous rating of the apparatus, or conductor rating. With heavily loaded circuits this could be the determining factor in whether a feeder could be successfully restored or not.

V. Load Encroachment in Distribution Automation

Without the DA system in place, PSE's standard utility practice has been to bypass recloser mechanisms when fed in an abnormal configuration. This ensures that reclosers will not miscoordinate with upstream devices or be the choke point if the phase pick up is set lower than the new downstream load. On DA systems, the load is constantly changing depending on the system configuration. A new method of determining the load limit of the device was needed, without the standard relay phase pickup of the recloser being the limiting denominator. A new solution was required to maintain proper coordination with devices, while allowing the system to restore heavily loaded sections from alternate sources.

The first generation of recloser mechanism and controller were ordered without voltage sensing so a method such as load encroachment was not possible to implement. If available fault current is adequate than other methods such as curve shaving, similar to a permanent cold load pickup scheme can be implemented. This works by setting the 51P element torque control above a desired load limit setting, 50P. Anything above this load limit setting would be considered a fault. This is not ideal as it removes a small portion of the curve and desensitizes the relay for lower magnitude faults. Despite this drawback, CTI margins for higher amperage faults can still be maintained. Figure 7 below shows a plot with this scheme implemented.

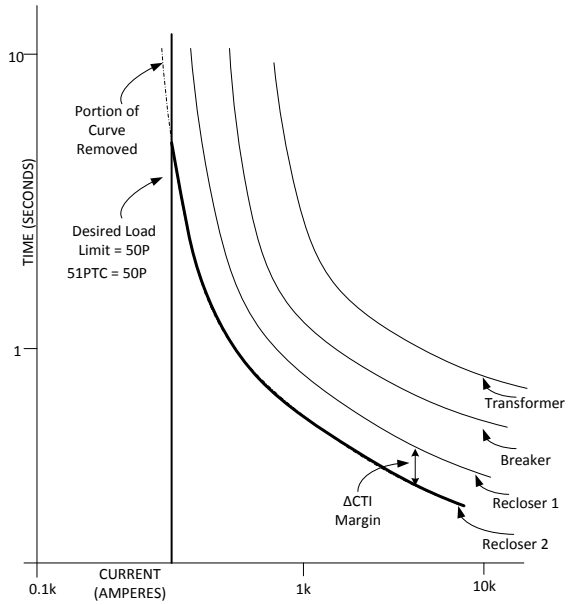

Figure 7 – Curve Shaving Technique for increased load limits

Load encroachment can be an effective means to distinguish between fault and load current. It is more commonly used on transmission lines where loads are more balanced between phases. On distribution systems, this may not be the same case. Care must be taken to ensure that normal load current imbalance does not defeat the load encroachment element in the relay. The relay must also be programmed to pick up for ground faults independently from the load encroachment settings. This ensures proper clearing for imbalanced faults independent of the phase element, which is torque controlled by the load encroachment element.

Given that the load encroachment element operates based purely on positive sequence quantities it can be susceptible to assertion during unbalanced faults. Unbalanced balanced faults contain all three sequence components so care must be taken ensure it is supervised appropriately. [3] The positive sequence portion of the fault quantities can erroneously assert the load encroachment element leading to undesired block of the torque control on the phase element.

Figure 8 shows a possible implementation of using load encroachment in a non-directional radial system. It is important that the 32QF and 32QR elements are set above the normal steady state imbalance or open phase condition of the system. These elements cover the case of accidental assertion of the load encroachment element for an unbalanced fault. The ground elements are still the primary protection for unbalanced faults, with the phase element as backup. The 50P element should be set above the desired load limit of the relay with an additional margin. Any currents above this magnitude are most likely a fault. This is a similar method to the curve shaving scheme above.

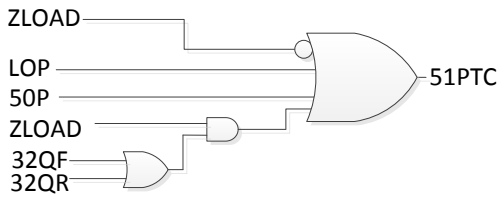

Figure 8 –Implementation of load encroachment on a non-directional 51P element

VI. CONCLUSION

Maintaining protection standards and guidelines while integrating distribution automation into a utility can be a challenging task. Existing protection standard should not be adapted to fit a DA system. DA system settings and configuration should be implemented to fit within the protection design standards of the utility. This allows for greater flexibility and standardization of relay settings and applications. It also creates a more robust power system that works with or without the DA scheme in place.

Given the complexity of the modern distribution grid protection systems are becoming more complex. They are requiring protection methods and techniques seen more regularly on the transmission system. By adapting proven protection methods end users can create DA schemes that will last well into the future.

VII. BIOGRAPHY

Louis Tibbs, P.E. received his B.S. degree in electrical engineering from Washington State University in 2008. Upon graduation, he joined the substation engineering group at Puget Sound Energy in Bellevue, WA. He has spent the past 9 years serving in a variety of roles including substation design, substation controls, and system protection. He has extensive experience with distribution protection system, reclosers, switchgear, and distribution automation schemes. He is the recipient of the 2014 Outstanding Young Engineer Award from IEEE Power and Energy Society, Seattle Chapter. He is also the class instructor for the 4th year substation wireman apprenticeship program at Puget Sound Energy. Mr. Tibbs is a registered professional engineer in the state of Washington.

VIII. REFERENCES

[1] IEEE Std C37.230-2007, “IEEE Guide for Protective Relay Application to Distribution Lines”, Part 7-1

[2] “Coordination Time in Feeder Relays”, GE Publication No. GET-8398

[3] “Guidelines for Applying Load Encroachment Element for Overcurrent Supervision”, George Alexander, SEL Application Guide AG20005-07

[4] IEEE Std C37.104-2001, “IEEE Guide for Automatic Reclosing of Circuit Breakers for AC Distribution and Transmission Lines”, Part 5-3