Return to Service Failure, Cooperative Troubleshooting

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Abstract -- **After completing a recloser control replacement at a customer's brownfield substation, the subsequent energized closure of the recloser resulted in an instantaneous recloser trip. No fault or equipment damage was apparent in the field. Electrical testing of the recloser was performed to determine its operational condition and found no problems related to the trip. Recloser control event data and sequence-of-events data was gathered and analyzed to determine the cause of the trip. The data presented by the recloser control did not fit classical fault event signatures which prompted further investigation. Field investigation and desk calculation determined that a significant circulating current event initiated when the recloser closed and caused the trip. This paper details the investigation of this event, highlights the critical characteristics to identify a circulating current event and displays the value of effective communication and coordination between field engineers and design engineers. Event root cause analysis and full lessons learned will be shared.**

I. Introduction

This paper will show that communication and cooperation between field and office personnel is imperative to quickly and accurately resolving complex operational issues in the utility environment. The issue that is the topic of this paper is the un-expected operation of a recloser while attempting to put it back in service after a planned construction outage, providing a real world look at a system condition that is not regularly encountered in system protection engineering work.

II. Planned Work

The planned work for the site was part of a program to replace older vintages of telecommunications equipment, analog metering equipment and protective relaying equipment. During this upgrade all other existing hardware was not modified. This project included updating equipment on three 4.16 kV feeders, denoted 3, 2 and 1 in Figure 1. Feeders were upgraded one at a time. During the upgrade work the subject feeder's load was transferred to another feeder so the subject equipment could be manipulated without risk of an un-expected outage.

The subject feeder of this paper is Feeder 3. The load on Feeder 3 was moved to Feeder 1 using a tie switch outside the perimeter of the substation. The order of operations to offload the feeder, as verified in switching orders, was:

1. Close field feeder-tie switch, providing parallel sources to the load on feeders 1 and 3
2. Open Recloser 3, adding Feeder 3 load to Feeder 1
3. Open disconnects on load and bus side of Recloser 3 to isolate it

With Feeder 3 offloaded and isolated, its protection control could be upgraded, tested and commissioned. In addition, legacy RTU, metering, and annunciator equipment for the station was to be retired and replaced with a more modern system. Figure 1 is a one-line diagram that shows the state of the system during the planned work.

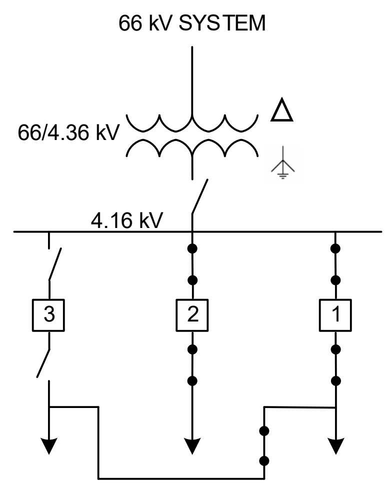

Figure 1 - System One-Line During Planned Work

III. Return to Service Failure

Upon completion of the planned work, Feeder 3 load was placed back on Recloser 3. The order of operations was:

1. Open Recloser 3

2. Close disconnects on load and bus side of Recloser 3
3. Close Recloser 3, providing a parallel source to feeders 1 and 3
4. Open field feeder-tie switch, isolating Feeder 3 load on Recloser 3

Figure 2 is a one-line diagram which shows the intended state of the system after restoration of Recloser 3.

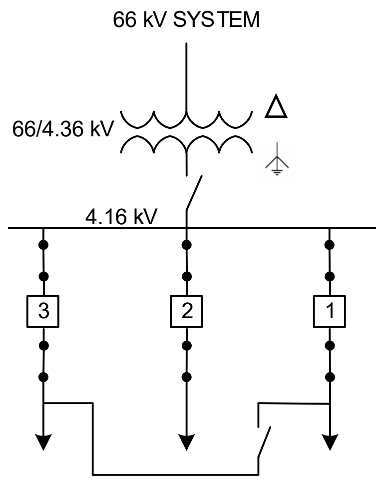

Figure 2 - System One-Line Diagram After Planned Work

Unfortunately, upon closing Recloser 3 in step 3 above, the recloser nearly instantly tripped open. The trip was un-expected, and the cause was not clear. Upon initial inspection of Recloser 3 and the surrounding station equipment no damaged equipment was apparent, and no signs of a fault were discovered.

IV. Investigation

A. Initial On-Site Investigation

Initial on-site investigation revealed an incorrect current transformer ratio (CTR) had been entered in the recloser control settings. The value was corrected and the recloser was closed. The recloser tripped again, nearly instantaneously after closing. Following the second failed close attempt, the decision was made to electrically test the recloser. Field engineers also decided to pass the recloser control event report data to office-based protection and control engineers for analysis concurrent with the recloser testing.

B. Office-Based Investigation

The office-based investigation began with a review of the recloser control event report shown in Figure 3.

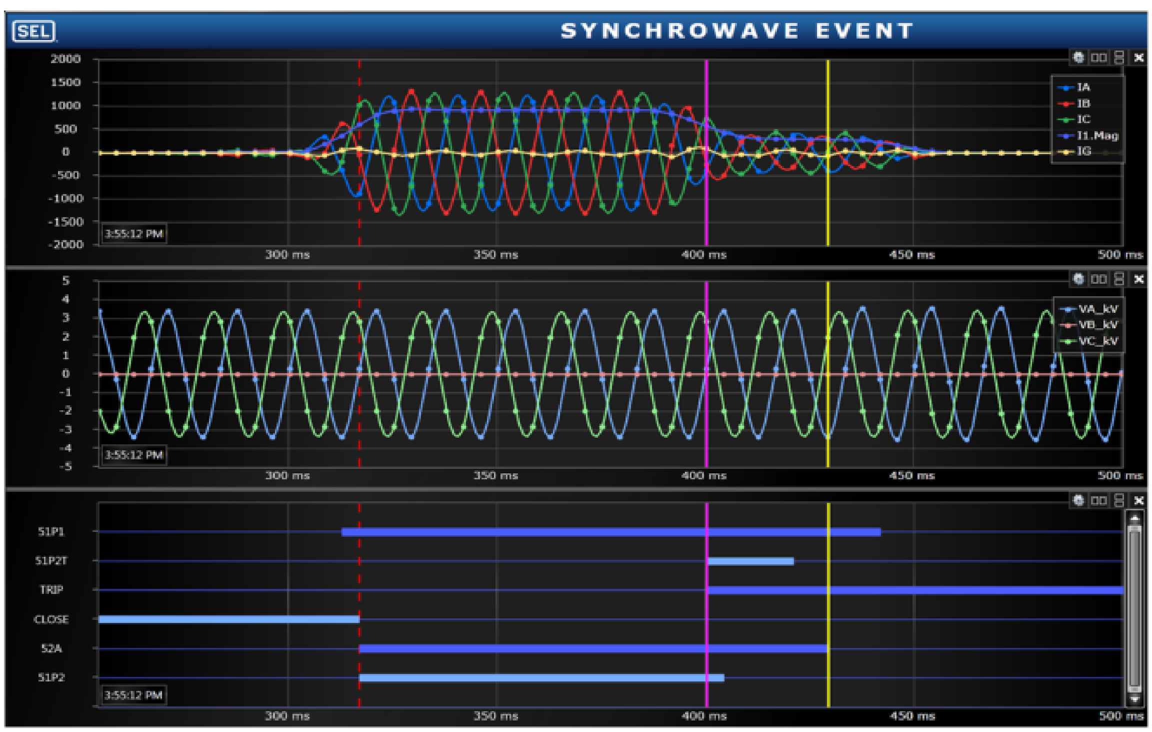

Figure 3 – Recloser Trip Event Report

Several interesting clues are immediately apparent:

- A phase-time over-current element timed out and tripped the recloser approximately 90 ms after the recloser was closed
- Balanced 3-phase fault
- No voltage suppression during the fault

These clues led to several dead-end discussions, some of the key items discussed were:

- Cold load pickup
- Internal fault in the recloser
- Possible faults in the substation at the disconnect switches
- Incorrect nominal relay current

In the office it was determined a fault in the recloser was not the cause as no damage was apparent on the recloser, bushings were intact, the recloser opened and closed successfully and there was no apparent external damage as one would expect to find when a recloser fails outright. Further, the lack of voltage suppression during the fault coupled with a fault that initiated three-phase, strongly indicated that this event was not a fault related event. During the office investigation it came to light that the recloser failed a contact resistance test and was to be replaced. The office-based investigation continued as the clues did not indicate high resistance contacts would cause the signature noted in the event report.

Multiple discussions with field engineers confirmed no failed equipment was found in the substation or on the distribution system immediately adjacent to the substation. In addition, Feeder 1 was still carrying the Feeder 3 load without issue which essentially ruled out a feeder-based issue.

The recloser control current input resistance was measured to confirm the control was in-fact a 1 A nominal control.

Cold load pickup was the event most clues pointed toward, however with Feeder 3 load being served from Feeder 1, this was clearly not a cold load pickup scenario as the load was continually served. In addition, Feeder one and Feeder three recloser controls were programmed with the same protection settings. The discussion did however lead to an additional field engineer walk down of the substation and the distribution equipment immediately adjacent to the substation to confirm that some kind of additional equipment wasn't fed from Recloser 3 exclusively somehow.

C. Field-Office Joint Investigation

The walkdown was conducted as a teleconference such that the field engineers could describe to the office-based engineers what they were seeing while the office-based engineers documented it. Figure 4 shows the notes taken during this walk down. Field engineers started at the Feeder 3 recloser and noted underground cable exited the station after roughly 150' and then noted near the overhead riser was a set of regulators. Following the regulator bank was another 1000' of cable and then the feeder tie switches which appeared to be new. Approximately 500' of overhead line connected Feeder 1 to the tie switches. Heading back toward the substation another regulator bank was encountered and then approximately 500' of overhead line lead to the Feeder 1 recloser.

While no un-expected loads were encountered, the regulator banks just outside the substation fence were equipment that had not been discussed previously and which did not appear on the available station one-line. After brief examination of the topology drawn during the walkdown, and based on previous transformer paralleling experience, it was suggested that circulating current resulting from regulator banks with mis-matched taps could have been high enough in magnitude to trip the recloser.

While still in the field, the field engineers noted the regulators were regulators which are standard 32 – 5/8% step regulators capable of +-10% regulation. They also recorded the as-found regulator tap positions as follows:

- Feeder 3 A-Phase +16
- Feeder 3 B-Phase +16
- Feeder 3 C-Phase +16
- Feeder 1 A-Phase +1
- Feeder 1 B-Phase +1
- Feeder 1 C-Phase +2

A quick hand calculation assuming a conductor impedance of 0.25 ohms indicated a circulating current of approximately 960 A would result if the feeders were paralleled with the regulators at the existing taps, which is 1.71 times the recloser control's 51P2 pickup setting of 560A. This quick calculation indicated more detailed study was warranted.

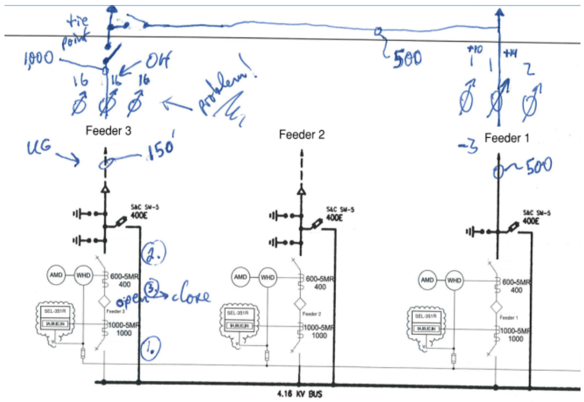

Figure 4 – Walk Down Notes

D. Additional Office-Based Investigation

In order to confirm the suspicion that the regulators were causing enough circulating current to trip the recloser, a circulating current calculation was completed using the following assumptions and information:

- The overhead line section was built similar to RUS C1.11 construction, primarily to determine conductor separation
- Conductor length estimates from the walk-down were used
- Overhead conductor size was estimated during the walk down to be 4/0 AWG
- Overhead conductor resistance was taken from the Southwire Overhead Conductor Manual [2]
- Overhead conductor reactance was taken from the ABB Red Book [1]
- Underground cable length was considered short enough that the overhead cable impedance was used for that section
- Load current was 250 A combined for feeders 1 and 3 which was recorded in the field by field engineers observing the feeder recloser controls and metering
- Load current was assumed to be split evenly between the two feeders, 125 A each
- To calculate a conservative, yet realistic scenario, the voltage regulators were assumed to be at +16 on Feeder 3 and 0 on Feeder 1, resulting in a 10% voltage difference

The calculation for the total current the recloser control would measure was:

$$\text{Calculated\_Current} := \frac{\text{Voltage\_Difference}}{\text{Total\_Impedance}} + \text{Load\_Current}$$

The result of this calculation was 752 A which when compared to the event report current of 900 A is approximately 20% different. Considering the assumptions that were made to complete the calculation this was considered confirmation that the tap mismatch between the Feeder 1 regulator bank and the Feeder 3 regulator bank was the cause of the recloser trip.

Field engineers noted that each feeder in the station was fitted with fused bypass switches. The fused bypass switches were not used for this work but presumably had been used historically. It was then noted that the field feeder-tie switch in the field looked to be newly installed. If the fused bypass switches had been used to bypass the Feeder 3 recloser the Feeder 1 and Feeder 3 regulators would not have been placed in a loop configuration and no circulating current would have been possible.

V. Conclusions

After reviewing the switching orders written for the planned work it was noted that the regulators on both feeders were not mentioned. Presumably the new feeder-tie switch and the looped regulator condition had not been considered historically as the fused feeder bypass switches would have been used for similar work and no loop condition would have been possible.

A recommendation to the operational staff was made to ensure Feeder 1 and Feeder 3 regulator bank taps were matched prior to attempting restoration of Recloser 3. Following that recommendation Recloser 3 was successfully placed in service on the first close attempted

In this case, close coordination and cooperation between field engineers who could observe real world conditions and convey accurate site-specific data to an office-based engineering staff in a controlled environment with analytic resources combined to achieve a quick and accurate solution to a complex problem. In contrast, a breakdown in communication between field operations staff and office-based operation staff, coupled with outdated prints and information, resulted in critical equipment (regulators) being ignored entirely in switching orders.

VI. References

[1] "ABB Electrical Transmission and Distribution Reference Book",1997

[2] *"Southwire Overhead ConductorManual"*, 1994

VII. Biographies

Jhobany Tortolero-Rojo joined POWER Engineers in 2015. He is a member of the Power Testing and Energization group where he performs a variety of commissioning, testing, and troubleshooting duties for transmission, generation, and industrial customers. His background is in protection and control for brownfield and greenfield substations. Jhobany holds a B.S. in electrical engineering from Gonzaga University.

Matthew Klein joined POWER Engineers in 2016. He is a member of the SCADA and Analytical Services group where he performs a variety of electrical system studies for transmission, generation, and distribution projects. He has a background in power system analysis, protective relaying, and arc flash studies. Matthew holds a B.S. and Protective Relaying Certificate in electrical engineering from the University of Idaho. Matthew is also an EIT in the state of Idaho.

Tony Limon joined POWER Engineers in 2015. He is a member of the SCADA and Analytical Services group where he performs a variety of electrical system studies for transmission, generation, and distribution projects. He has a background in power system analysis, protective relaying, and arc flash studies. Tony holds a B.S. in electrical engineering from Washington State University.

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