GREGG 230 KV SUBSTATION SHUNT CAPACITOR BANK FAILURE AND CASCADING AREA DISTURBANCES

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Abstract

This paper provides a critical evaluation of a High Voltage (HV) Shunt Capacitor Bank catastrophic failure at Gregg Substation on June 16, 2016. Discussed are cascading events which led to sustained and momentary outages affecting more than 115,697 customers in a large Transmission and Distribution area. Existing methods of protecting HV Fuseless Shunt Capacitor Banks at Pacific Gas & Electric Company (PG&E) are also discussed related to this major event. Presented in details are root cause analysis ascertained to have caused expanded area disturbances. Primary corrective actions and lessons learned are addressed to merit avoidance or mitigation of similar unique and unusual incidents.

Power System Overview and Events Summary

Gregg 230 kV Substation serves as the main interconnection point to the Bulk Electric System (BES) for the Helms Pumped Generation Plant (PGP) of 1200 MW. It is located in the Fresno area approximately 50 miles to the southwest of Helms PGP.

On Thursday June 16, 2016, at 15:55 the Gregg Cap Bank 1 experienced a catastrophic failure as a result of a single phase switching condition from Disconnect Switch (DSW) 211 to CB 212. The breaker phase C did not open as indicated on the semaphore due to a separated pushrod linkage to C phase (center pole). This event caused a sustained outage to 76,517 customers, momentary outages to 39,180 customers, for a total customer count of 115,697. The event caused extensive damage to the capacitor bank, fortunately there were no injuries. Approximately 200 MW of load was lost. In addition, several generating facilities tripped off-line as a result of this major disturbance. The failure led to the sustained loss of Gregg Substation and several of its remote terminals. The capacitor bank fire was extinguished and the failed capacitor bank was isolated. The restoration of the impacted systems began immediately and by 16:43 the affected distribution substations were re-energized. By 17:26 the affected BES lines were restored successfully.

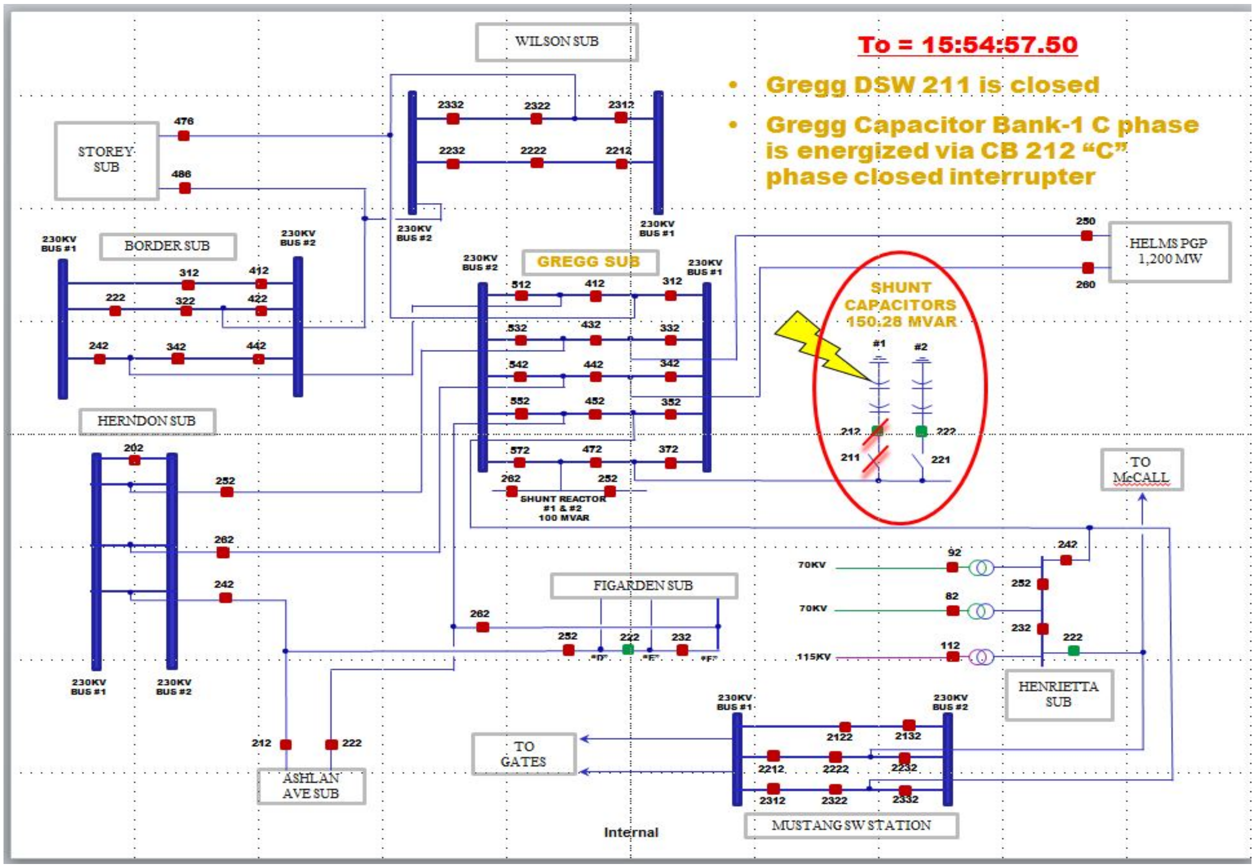

Figure 1 Power System Overview of Gregg 230 kV Substation

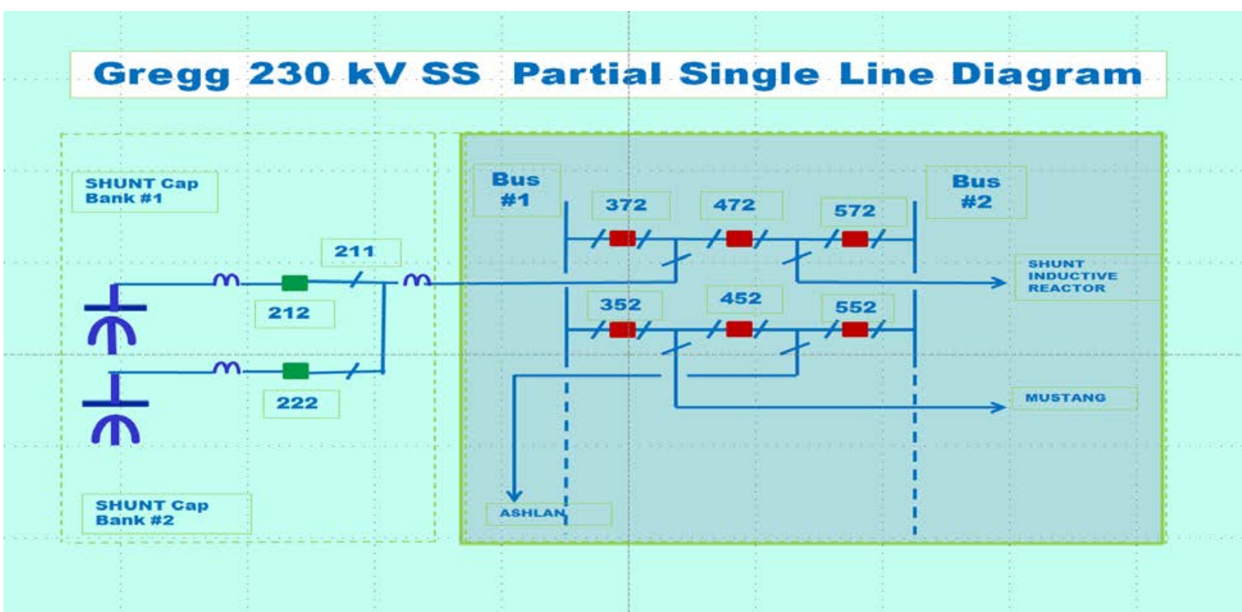

Figure 2 Partial Single Line Diagram, Gregg 230 kV Substation, Shunt Capacitor Bank 1

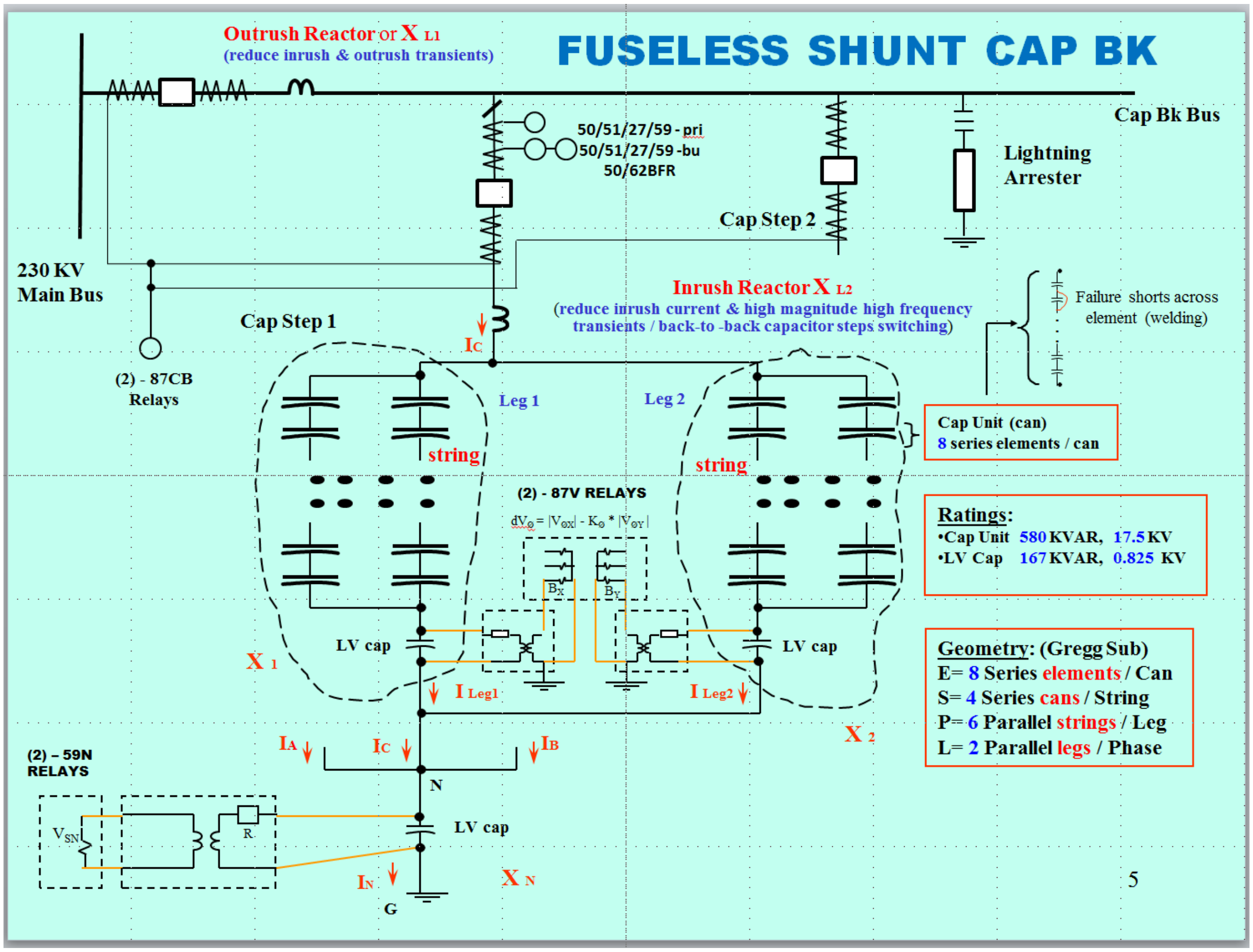

Figure 3 Single Line Meter & Relay Diagram

Figure 3 shows a Single Line Meter & Relay Diagram of a PG&E Fuseless Capacitor Bank design at Gregg 230 kV Substation.

The protection scheme is designed to provide high speed clearing of capacitor banks and capacitor bus for fault conditions. It also provides security for incorrect operation during external faults.

Each capacitor bank step has protective relays as follows:

- Overcurrent Protection, 50/51 – Primary and Back up
- Breaker Failure Protection, 50 BF
- Voltage Differential Protection for Phase Capacitor Units, 287V – Primary and Back Up
- Low Voltage Neutral Overvoltage Protection, 59N – Primary and Back up
- Undervoltage and Overvoltage Protection, 27/59 – Primary and Back up
- 230 kV Capacitor Bus Differential Protection, 287CB – Set A and Set B

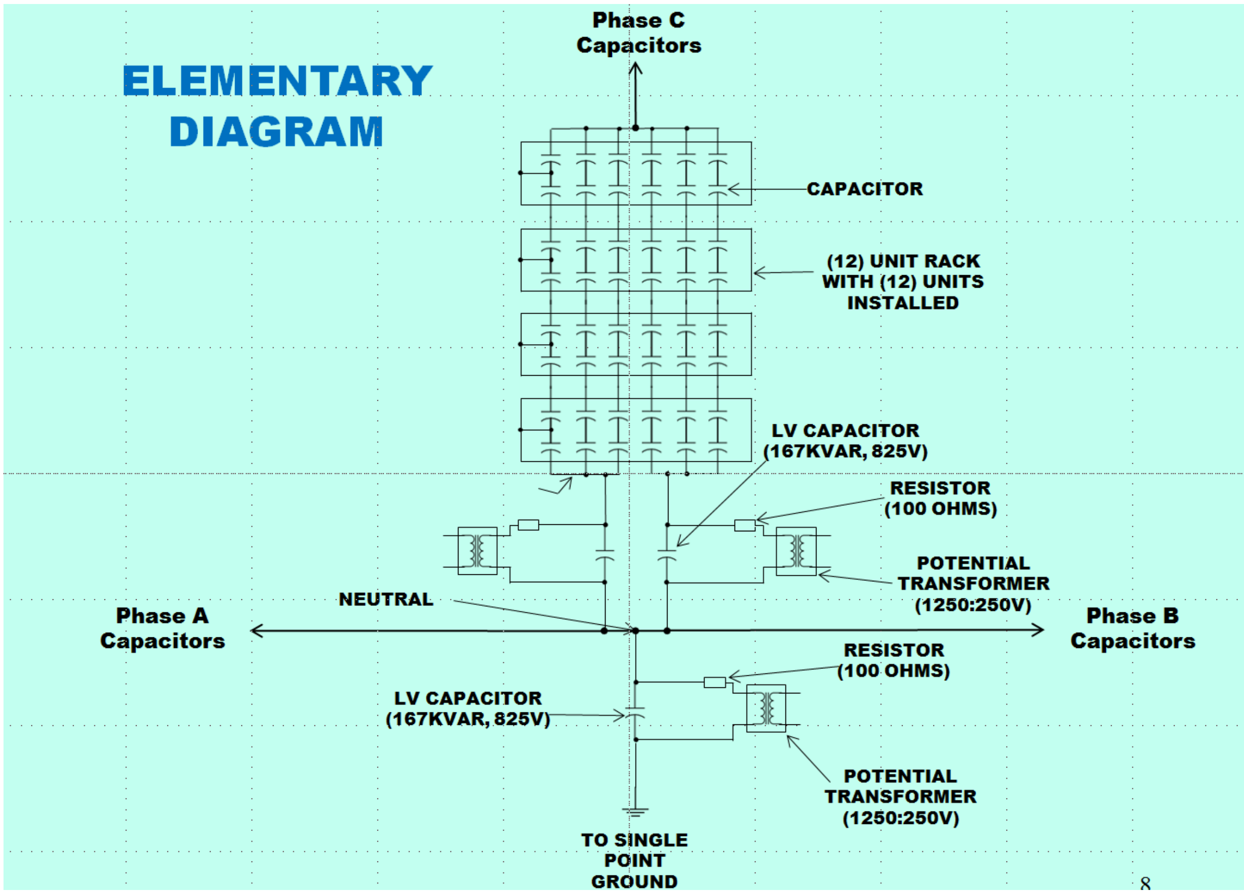

Figure 4 Shunt Capacitor Bank Elementary Diagram, Phase "C"

Review and Analysis of the Sequence of Events

During the Event, 6/16/2016

1) At 15:54, switchman verified that CB 212 was open at the semaphore (position indicators).

2) At 15:55 on switch log FR16-1687, the switchman attempted to close gang operated switch, DSW 211 (energizing up to what was supposed to be an open CB 212). Switchman heard arcing from the live parts of DSW 211 and loud sounds generating from CAP BK-1. The switchman ran for safety with DSW 211 remaining in the partially closed position.

3) Relay devices 267-C1 and 267BU-C1 for CB 212 operated by Neutral Overvoltage protective element, which attempted to trip and initiate breaker failure retrip to CB 212. Phase "C" main contact remained closed due to fractured rod-end eyelet bolt on the C phase center pole.

4) The initial continuous current level from CAP BK-1 fault (approximately 180 amps primary) was below the as-found pickup values found on the breaker failure relay device 250/262BF-C1.

5) The timer on the breaker failure relay device 250/262BF-C1 had exceeded the control timer and no longer would allow a breaker failure function to trip CB's 372 and 472 until it could be

reset. The breaker failure initiate input was continuously picked up, not allowing any reset of the breaker failure control timer. This also prevented CB's 372 and 472 from tripping during the event.

6) 15:56 hours Gregg Cap BK-1 failed catastrophically and erupted into flames and smoke.

7) The current on Gregg Cap BK-1 began to rise to fault levels approaching 14,600 Amps.

8) The Gregg 230 kV buses 1 and 2 are set up in a Breaker-and-a-Half configuration equipped with bus differential protection and are not designed to capture a unique fault event such as the one generated by the CAP BK-1 fault. This allowed the remote substation terminal relays to pick up as a means of remote back up protection to isolate the fault on Gregg CAP BK-1. The remote terminal protection breakers that tripped toward Gregg Substation were Herndon 242, 252, 262, Wilson 2312, 2322, Mustang Switching Station 2322, 2332, Borden 242, 342, and Henrietta 242 – clearing the fault on Gregg CAP BK-1.

9) After all 10 of the remote terminal circuit breakers tripped to clear the fault, all Gregg circuit breakers opened by Power Fail operation as designed with the exception of CB 212 due to the mechanical failure on C phase. CB 572 indicated closed, however further inspection revealed a broken position indicator and seal stack linkage. CB 572 main contacts did in fact open by Power Fail as designed.

Summary of Findings:

In depth analysis and investigation focused on the following questions:

1. Why did Gregg CB 212 not operate as designed on this fault?
2. Why did neutral capacitors on the low voltage terminal fail catastrophically?
3. Why did the breaker failure on CB 212 not trip upstream capacitor bus differential relays and isolate the faults locally at Gregg 230 kV capacitor bus?
4. Why did Ashlan 230 kV distribution loop station experience a sustained outage with pilot directional comparison blocking scheme in service?
5. Why did Gregg CB 572 not operate as designed as shown on SCADA screen of Grid Control Center?

1. Why did Gregg CB 212 not operate as designed on this fault?

a) The operating rod was out of adjustment as evidence of mechanical stress indicated on the rod-end eyelet bolt.

b) The threads on the front side of the rod-end eyelet bolt were compressed together while the rear side threads were spread apart indicating that the mechanical failure of the rod-end eyelet occurred during the last close operation that took place on Monday 06/13/16 at 02:54 hrs.

c) The rod-end eyelet bolt appeared to have been fractured on the rear side for some time to allow a small portion of the metal to grind smooth and flat, and the remainder of the eyelet bolt material finally snapped due to fatigue.

d) The left pole showed evidence of over-travel as a small mark on the rod was evident on the top side of the operating pullrod surface where it had been making contact with the bellcrank assembly.

e) Removal of the upper retaining pin revealed excessive wear at the interphase shaft slots and it is believed that the wear could explain the minor over-travel.

The mechanical failure point was obstructed by a protective shroud above the breaker mechanism cabinet furthermore concealing the issue.

Figure 5 CB 212

Figure 6 CB 212 rod-end eyelet bolt

Figure 7 CB 212 rod-end eye bolt with retaining ring

2. Why did the Neutral Capacitors on Low Voltage terminal failed catastrophically?

The partial energization of DSW 211 to the Capacitor Bank 1 on Phase C only, caused an unusual Phase Voltage Imbalance that produced a shift of Neutral (N) star point to Ground (G) point. The Phase C Voltage to Neutral, VCN, shifts to Phase C Voltage to Ground, VCG, when phase imbalance occurred without Phase "A" and Phase "B" of the Capacitor Bank energized.

Based on the events retrieved from microprocessor relays, prolonged voltage impressed on the neutral caps was seen exceeding 1100 volts rms, or 1556 volts peak voltage, and 2400 volts 3V0, Zero Sequence Voltage, for more than 65 seconds. This 1100 volts rms is 133% above the rated terminal voltage, 825 volts rms, of the Neutral Capacitors. This explain why the single line to ground fault took so long to develop (**65 seconds)** as it gradually broke down the LV Capacitor insulation until it catastrophically failed. **LV Capacitor voltage surge** was due to **single phase arcing of the disconnect switch 211 to the capacitor bank Phase C.**

From **Table 1** shown below from IEEE STD. 18-1992, for a continuous overvoltage in excess of 130% of rated rms voltage, the duration limit for short time power frequency overvoltage was only 1 minute for the capacitor to withstand.

Duration	Maximum permissible voltage (multiplying factor to be applied to rated voltage rms)
6 cycles	2.20
15 cycles	2.00
1 s	1.70
15 s	1.40
1 min	1.30
30 min	1.25

Table 1 IEEE STD.18-1992 Capacitor Overvoltage Short Time Withstand

The voltage transients surge (**3V0, VS**), as seen in the following graph in **Figure 8** could be attributed to voltage instability during inrush, high frequency harmonic current, or unsynchronized closing of breaker pole on zero degree crossing. One or more of these conditions may have transpired by the nature in which the capacitor bank was inserted into the system using a partially closed Switch 211 on Phase "C" only. Harmonic Analysis showed presence of 2^{nd}, 3^{rd}, 4^{th}, 5^{th}, 6^{th} and 7^{th} harmonic currents ranging from 5.35 – 10.16 amps on top of fundamental current, 128.3 Amps.

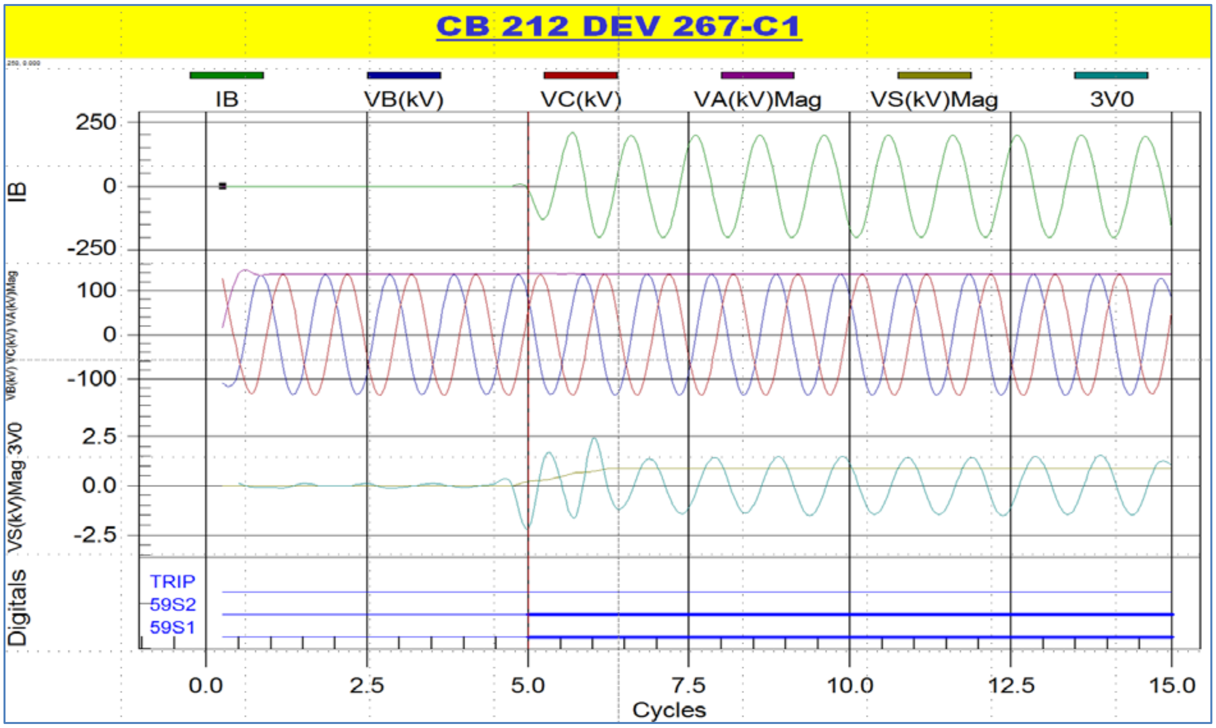

Figure 8 CB 212, Device 267-C1 Oscillography

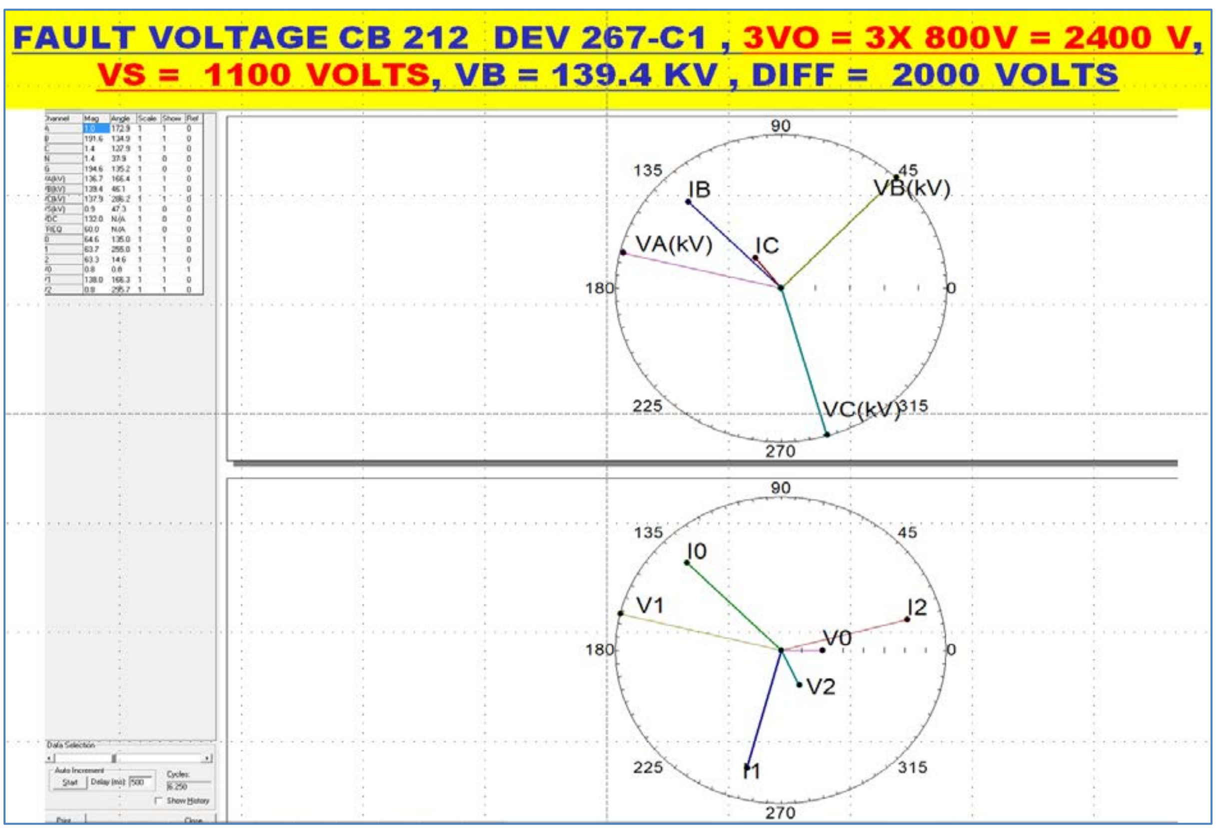

Figure 9 CB 212, Device 267-C1 Phasor Diagram

PG&E Applied Technology Services (ATS) noted also the same cause of catastrophic failure on the low voltage neutral capacitors. It was prolonged exposure (65 seconds) to an over-voltage event which resulted in internal insulation breakdown and rupture of the capacitor tank due to the high pressure gas produced by internal arcing.

Figure 10 Capacitor Bank 1 with Phase "C" String Damage

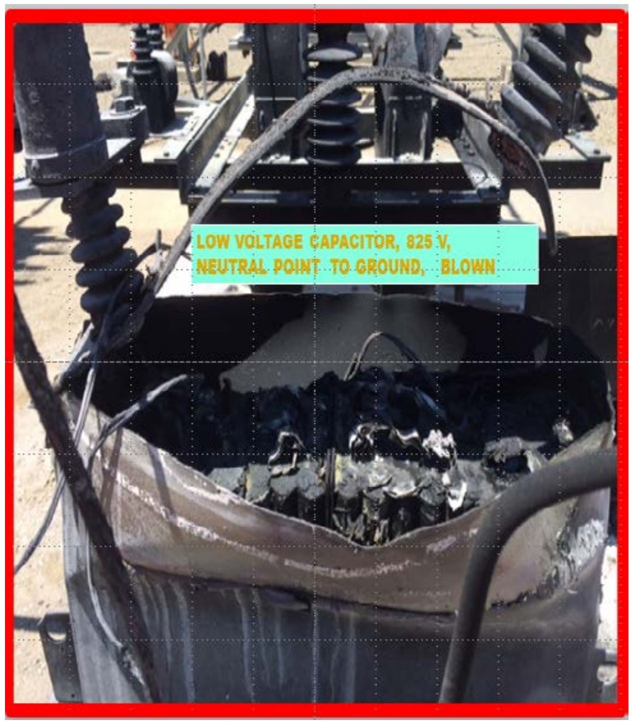

Figure 11 Low Voltage Neutral Capacitor Blown

3. **Why did the breaker failure relay on CB 212 not trip upstream Capacitor Bus Differential relays and isolate the faults locally at Gregg 230 kV Capacitor Bus?**

   a) The low voltage capacitor neutral overvoltage protection (59S1 & 59S2) operated as designed and expected from both primary and back up microprocessor relays. It provided protection trips (breaker failure initiate) to Gregg CB 212 breaker failure relay to immediately Retrip, and after 8 cycles Breaker Failure Trip to the upstream Capacitor Bus Differential relays provided the breaker failure phase or ground current fault detector picks up. However, errant settings for phase and ground current fault detector pick up were found not matching the issued and desired settings on breaker failure relay 250/262BF-C1. The errant settings were changed in the field for unknown reasons during maintenance.

   b) Breaker failure phase and ground fault detector pickup values at Gregg CB 212 were found high on the as-left settings of the relay from previous maintenance testing on July 2015.

   c) Breaker Fail Ground Pickup was found at **1.5 amps (360 A)** from **0.5 amps (120 A).**

   d) Breaker Fail Phase Pickup was found at **5.0 amps (1200 A)** from **1.0 amps (240 A).**

   e) The initial continuous current level from CAP BANK 1 fault (180 A primary) was below the ground pick up values set on the breaker failure relay device 250/262BF-C1. There was no substantial fault detector current pickup to allow breaker failure trip operation.

f) The timer on the breaker failure relay device 250/262BF-C1 had exceeded the control timer and no longer would allow a breaker failure function to trip CB's 372 and 472 until it could be reset. The breaker failure initiate input, IN3, was continuously picked up; not allowing any reset of the breaker failure control timer which prevented CB's 372 and 472 from tripping during the event.

g) The Breaker Position input, IN1, to the breaker failure relay indicates Open Breaker, 3-semaphore indication showed open breaker. There was **NO Breaker Position indication that it is still Closed, in order to allow breaker failure trip operation.**

4. Why did Ashlan 230 kV distribution loop station experience a sustained outage with Pilot Directional Comparison Blocking scheme in service to Herndon Substation?

The Herndon CB 242 terminal of the Ashlan – Herndon 230 kV line over tripped when there was a momentary loss of blocking signal received from Ashlan Substation. This overtrip resulted in the loss of Ashlan and Fig Garden distribution substations. The high speed reclosing (HSR) did not initiate at Herndon CB 242 due to a missed directional ground element (67G2) at High Speed Reclose Initiate logic output contact.

A Carrier Hole (blocking signal lost) in Herndon 242 pilot line relay caused the over trip as shown in the relay event oscillography in **Figure 12** below. Herndon 242 did not High Speed Reclose although it was Cut In per Grid Control Center (GCC). Based on the event oscillography, OUT101, High Speed Reclose (HSR) Initiate did not have 67G2 relay element but it tripped by 67G2 when Carrier Hole in IN103 lasted for 2 cycles.

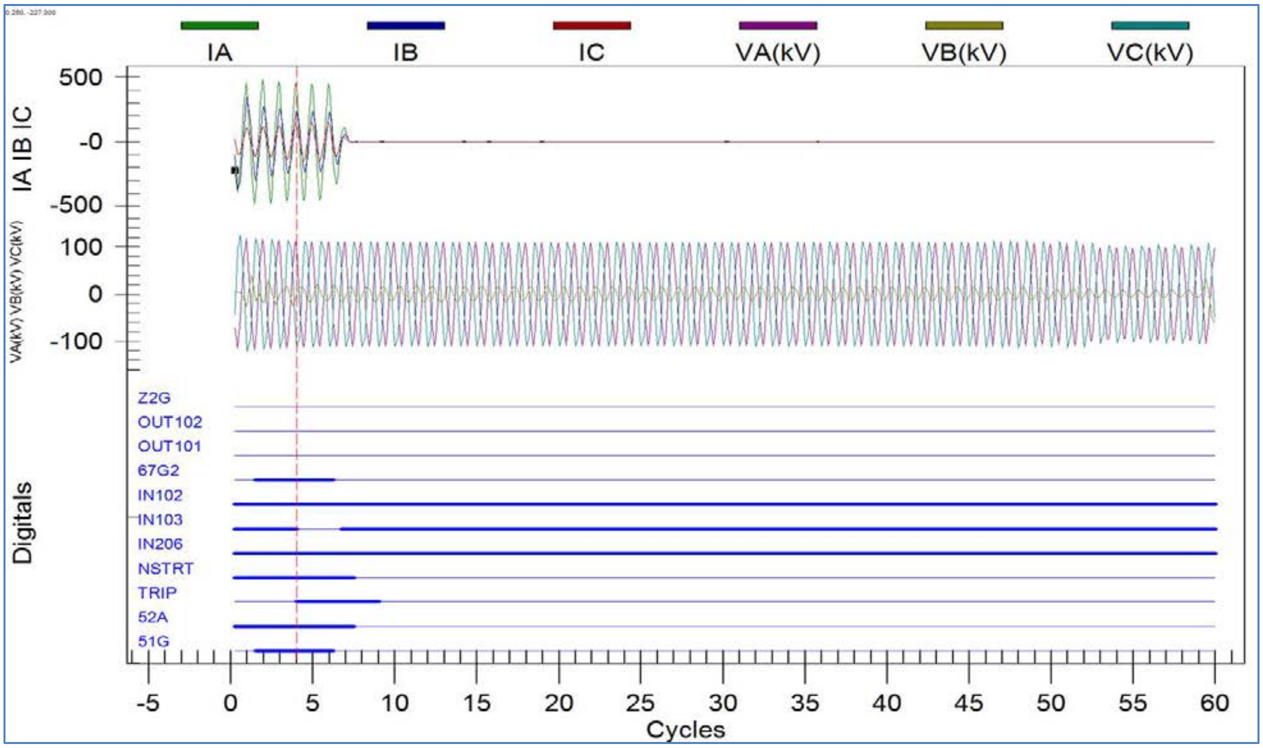

Figure 12 Herndon CB 242 Relay Oscillography

The Ashlan Directional Comparison Blocking Carrier scheme did not operate as designed during this event due to a failed Power Amplifier Transmitter, 285AC-1, and a failed Carrier Ground Relay, 267NC-1.

5. Why did Gregg CB 572 not operate as designed?

Grid Control Center (GCC) operator noticed that CB 572 continued to indicate closed after the event via SCADA screen. CB 572 was really open but did not indicate at the time of event. Substation maintenance crew cleared CB 572 to troubleshoot and found this breaker also had a broken linkage (called lever for this breaker) as well as a burned trip and close coil. The coil failures were a result of the broken lever, shown in **Figure 13**.

PG&E ATS analysis determined that the failures of the linkage lever metal were attributed to interconnected voids formed in the metal due to solidification shrinkage during original manufacturing process. This is coupled with high operational stresses arising from the sliding motion over the shoulder bolt when the breaker was operated frequently. The ATS report compared well with circuit breaker manufacturer recognition of the same problem occurring on similar breakers belonging to other utilities.

Figure 13 CB 572 Broken Linkage Lever

Positive Findings

- A thorough job tailboard was conducted prior to the switching work.
- The crew contacted Grid System Operations immediately communicating what transpired during switching.
- Excellent coordination and restoration efforts.

Recommendations and Actions

- Replaced Gregg CB 212 with new synchronous control unit, zero voltage crossing closing circuit breaker.
- Checked all other breakers for similar problems.
- Replaced Phase “C” Capacitor Bank units and associated metering and relaying components.
- Corrected breaker failure relay settings on Gregg CB 212.
- Checked and verified all other breaker fail relay settings matched the setting of record.
- Replace Gregg CB 212 and CB 222 breaker failure relays with new microprocessor relays per PG&E strategy and to modernize and incorporate additional security features.

Lessons Learned

- Testing and visual inspection after adjustments to CB 212 did not reveal mal-adjusted operating rod on Phase “C”. The circuit breaker design provides no external indication that internal linkage was broke and the main breaker contacts are closed.
- Changed the trigger points for breaker inspections and include velocity / timing tests

on the maintenance cycle.

- Tailboard this unusual event, the root cause and socialized changes with maintenance personnel to the maintenance procedure.
- Relay settings were changed in the field and procedures were not followed.
- Socialized this event with Maintenance Techs and Protection Engineers regarding procedures to change relay settings in the field. All relay settings changes must be communicated and documented in relay database.
- Continue PG&E strategy to control relay settings by tracking the person making the change and the change being made following newly implemented relay settings workflow process.

Conclusions

1. Disconnect Switch (DSW) 211 partial energization of only Phase “C” of Capacitor Bank 1 caused an unusual phase imbalance that produced a shift of Neutral (N) star point to Ground (G) point. The arcing of DSW 211 during switching provided high inrush currents and developed an excessive neutral overvoltage condition from Ground (G) up, exceeding voltage rating of the LV Neutral Capacitor. Prolonged continuous full load current of 200 amps impressed to Neutral (N) Point to Ground, coupled with excessive neutral overvoltage consequently caused breakdown of internal insulation and rupture of the capacitor tank due to the high pressure gas produced by internal arcing.

2. The failure of Gregg CB 212 Phase “C” operating rod triggered a sequence of additional failures and events that led to the catastrophic failure of Gregg CAP BK-1 Phase “C”. Breaker manufacturer concluded that the failure was attributed to a mis-adjusted operating push rod. PG&E ATS concluded that the component failed by predominantly ductile over load fracture.

3. Gregg CB 572 failure of the operating linkage lever was concluded by PG&E ATS to the pre-existing solidification shrinkage defect in the equipment and high operational stresses over the shoulder bolt during frequent operation.

4. The installation of redundant protective relays in PG&E fuseless shunt capacitor bank design improves dependability, efficiency and reliability in monitoring, detecting and alerting maintenance and operations personnel. No guarantee of 100% full proof protection when errant relay settings creep in from nowhere and left unverified.

REFERENCES

(1) ANSI/IEEE Standard 18-1992, IEEE Standard for Shunt Power Capacitors

(2) ANSI/IEEE C37.99-1990, IEEE Guide for Protection of Shunt Capacitor Banks

BIOGRAPHIES

Leo B. Hisugan is a Supervising Protection Engineer in System Protection Engineering at Pacific Gas and Electric Company, California. Leo has a BSEE degree from Central Philippine University as the Most Outstanding Electrical Engineering Graduate in 1985. He has a Master of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute, New York in 1996. He completed Georgia Tech Power Systems Certificate Program at Atlanta, Georgia in 2017. He is a member of IEEE and a registered Professional Engineer in the State of California and US Territory of Guam. He was a Power System Superintendent in Meter and Relay for Guam Power Authority in 1999. Leo has over 32 years of experience in the application of protective relaying and control systems from 480V up to 500 kV Transmission Transformers, Generating Power Plants, Pilot / Non Pilot Transmission Lines and Distribution Lines up to 230 kV system. He previously worked in Power System Control Center Operation, Substation / Power Plant Construction, Design and Operation for National Power Corporation in the Philippines and Guam Power Authority respectively from 1986 to 1999.

Aaron Feathers is a Principal Engineer in System Protection Engineering at Pacific Gas and Electric Company, where he has been employed since 1992. He has 26 years of experience in the application of protective relaying and control systems on transmission systems. Aaron's current job responsibilities include design standards, wide area RAS support, NERC PRC compliance, and relay asset management support. He has a BSEE degree from California State Polytechnic University, San Luis Obispo and is a registered Professional Engineer in the State of California. He is also a member of IEEE and is on the Western Protective Relay Conference planning committee and participated on the NERC Protection System Maintenance Standard Drafting Team developing NERC Standard PRC-005-2 to PRC-005-6.

Fortino Arroyo Rivera is an Associate Protection Engineer with Pacific Gas & Electric Company in California. In 2012, he received his Bachelors of Science & Masters of Science in Electrical Engineering with an emphasis in Power from California State University, Los Angeles. In the same year he also obtained his Engineering-In-Training (E.I.T) certification for the state of California. Fortino has 5 years of industry experience with power system studies, substation design, and protective relaying.