Analysis of unfaulted 115kV line over-trip by multiple grounds in VT secondary circuits at National Grid

By: Song Ji and Yujie Irene Lu, National Grid USA

Introduction

A single line to ground fault occurred on 115kV line L114 on September 2nd 2011. Protections on both ends of the line operated and tripped line breakers to isolate the fault. However, relay targets and fault locator information from one line terminal seemed to be contradictive. In the mean time, the unfaulted line L103 connected to one line terminal (station L) was unexpectedly tripped by an electromechnical distance relay with a target of directional ground distance zone 1 (21N-Z1). Per relay records obtained from station L, the magnitude of all three-phase voltages of the faulted line L114 was elevated to abnormal high values with erroneous phase angle. The similar line to ground fault occurred on the same L114 line few months ago, but VT secondary voltages looked reasonable.

Correct and rapid fault clearance and power outage minimization are the most concern of utility companies. The protection schemes shall work properly to isolate faults promptly and minimize the impact on transmission system. This paper presents an analysis of the event utilizing fault records of digital relays to determine the nature of the fault and what happened and why the unfaulted line was tripped. The fault records captured by IED provided valuable information which gave an insight into the nature of this disturbance while computer based short circuit program confirmed the analysis. The analog and digital data of fault records facilitate an efficient investigation and accurate analysis of this event.

System Overview and Incident Summary

115kV substation L is a switching station with twelve transmission lines; no ground source is available at the station. The simplified electrical system diagram is shown in Figure 1.

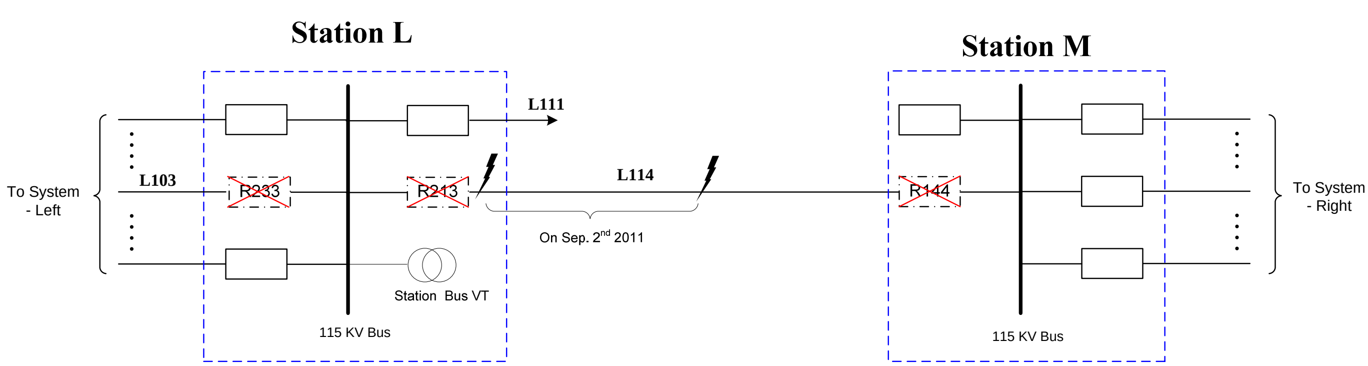

Figure 1: the simplified electrical system

115kV line L103 runs between station L and one of upstream source stations; line L114 connect station L & M. At station L, 115kV line L103 & L114 are connected to station bus via 115kV breaker R233 and R213 respectively. All the transmission lines are provided with dual protection systems for line phase and ground fault. At station L & M, two complete digital relay packages are provided for line L114 protection. For 115kV line L103 at station L, dual electromechnical relays are provided.

At station L, the current inputs for line protective relays are from corresponding bus side breaker bushing CTs. The voltage inputs of different distance relays are from the secondary of common 115kV bus VT. For each line at station L, only one-phase VT is installed on the line side for line reclosing purpose.

At 12:08:05AM of September 2nd 2011, the National Grid Control Center reported that:

115kV line L114 was tripped from both station L & M. In the mean time, 115kV L103 was tripped from station L terminal only. The relay targets information is below:

Station L:

115kV line L114:

System - 1 relay (digital): C- phase Ground distance (Z1G);

System - 2 relay (digital): C- phase Ground distance (Z1G) & Instant, directional ground OC (67G1);

System 1 & 2 relays are from the different manufacturers.

115kV line L103:

System - 1 relay (electromechnical): Phase B Ground distance zone 1;

System - 2 relay (electromechnical): No operation;

Station M:

115kV line L114:

System - 1 relay (digital): C- phase Ground distance (Z1G) & Instantaneous ground overcurrent (67G1);

System - 2 relay (digital): C- phase Ground distance (Z1G) & Instantaneous ground overcurrent (67G1).

Both system 1 & 2 relays are from the same manufacturer. The fault locator of both relays indicated the fault was on the end of the line or remote end.

Investigation and Analysis

The first step of the investigation was to collect and review relay targets, sequence of event, and the digital relay fault records from both station L & M. Based on the reported relay targets and the fault records captured by relays, it was confirmed that there was ground fault on 115kV line L114 and breaker R233 of line L103 at Station L should not have been tripped on the irrelevant line L114 fault. However, the relay targets and fault locator information for line L114 at station M seemed to be contradictive since relays operated by instantaneous element while both fault locators showed the line end fault. Later, the visible burning marks were found on the take-off line structure of line L114 at station L, which confirmed a close-in ground fault occurred on line L114 close to station L.

Relay records from Station L:

The record of line L114 system 2 relay at station L is shown Figure 2 below. It can be seen that a C-phase to ground fault occurred on the line and 15kA ground current was present. C-phase ground distance zone 1 element (Z1CG) and instantaneous directional ground overcurrent element (67G1) asserted right after C-phase to ground fault inception. The assertion of negative sequence direction element (32Q) did indicate the fault was forward direction. The line breaker R213 was then correctly tripped to isolate the fault.

It should be also noted that all 3-phase voltages recorded by the relay were elevated to high magnitude with small phase angle shift. Since the neutral of 115kV system in that region is effectively grounded, at least the magnitude of the faulted phase voltage should have been decreased during the fault rather than increased to an abnormal high value.

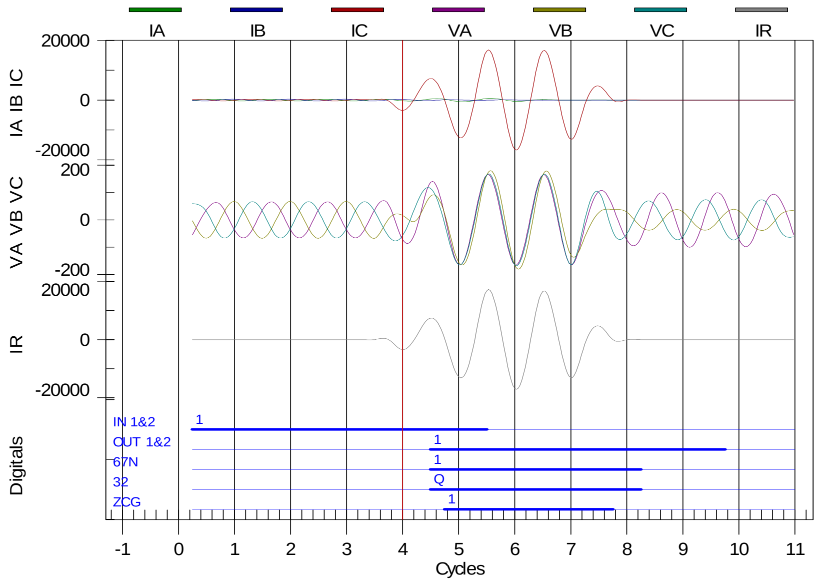

Figure 2: the system 2 relay record of Line L114 at station L on September 2nd of 2011

The system 1 relay record of line L114 at station L was reviewed as well and is shown in Figure 3. C-phase ground distance zone 1 element (Z1G) correctly asserted right after the fault inception. However, it can be seen that the faulted C-phase current measured by the relay was not sinusoidal and truncated from the peak while current waveform from system 2 relay didn't have that issue. This was caused by internal CT saturation inside the system 1 relay, which has been observed and known for some time.

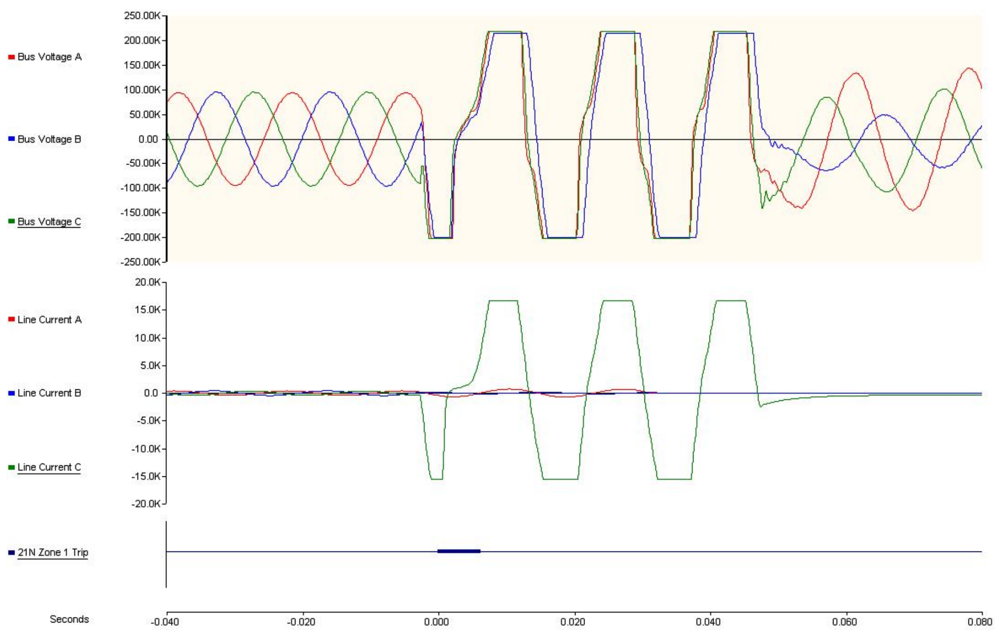

Figure 3: the system 1 relay record of Line L114 at station L on September 2nd of 2011

The measured voltages by L114 system 1 relay were square waveforms with high magnitude during the fault. Apparently, the measurement circuit of system 2 relay can't handle the excessive overvoltage applied to the relay. It is necessary to check and compare the voltage measurement from other relays with the same type or manufacturer of system 2 relay at station L and see how the relay from different manufacturer reacted to this event. The system 2 relay of Line 111 at station L was triggered as well during line L114 fault. Its record is shown in Figure 4.

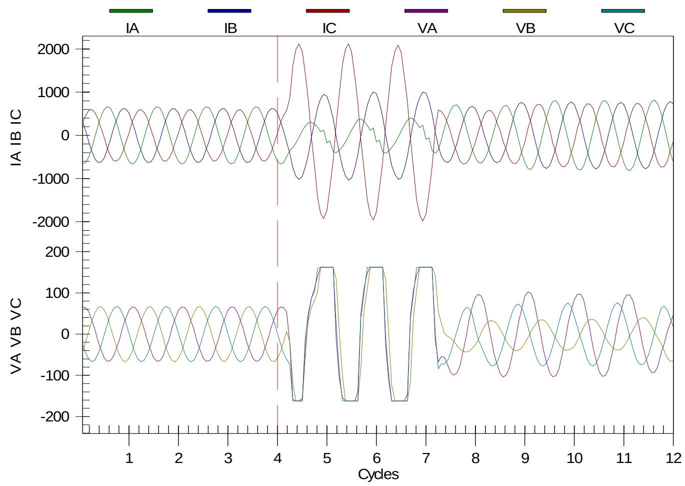

Figure 4: the system 2 relay record of Line L111 at station L on September 2nd of 2011

The relay saw the fault as reverse and didn't misoperate on the line L114 fault. However, the same odd voltage was present as seen by system 1 relay of line L114. System 2 relays for line L111 and L114 are of the same type and from same manufacturer. Since relays got voltage from same bus VT, why did two relays record have different voltage waveforms?

On May 15th of 2011, the same type of C-phase to ground fault happened on line L114. Protections for the line fault operated correctly. It is necessary to review the previous relay records and see what voltage waveform was recorded at that time. Figure 5 shows system 2 relay records of line L114 at station L on May 15th of 2011.

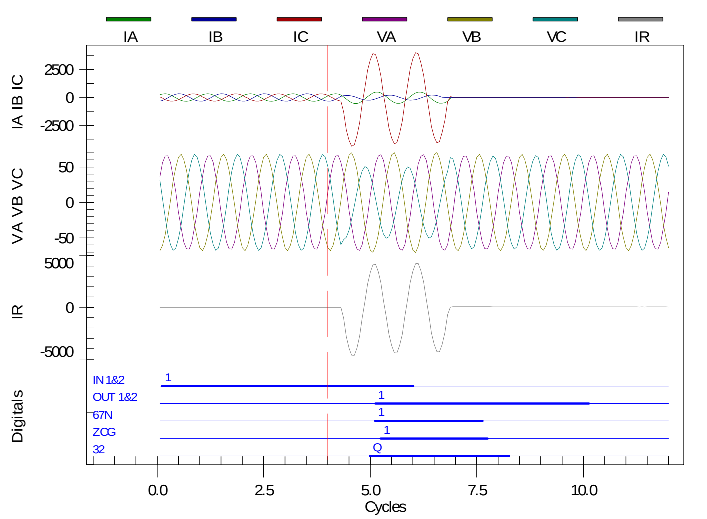

Figure 5: the system 2 relay record of Line L114 at station L on May 15th of 2011

The fault was 8.68 miles from station L per fault locator and the ground current from station L was 4.1kA as seen in Figure 5. The recorded voltages look quite reasonable and symmetrical. Comparing the relay records, it can be seen that the differences of two events on May 15th and September 2nd are the magnitude of ground fault current and the fault location. The abnormal voltages seen by relays only occurred during the close-in ground fault; therefore it is necessary to take a look on the grounding system of station L before performing further investigations.

Substation grounding grid system

At each distribution and transmission station, the grounding grid system is required for safety reasons. The effective ground grid is designed to limit the voltage on the surface equipment in the substation area, thus the touch and step voltage inside of station can be limited to the allowable values. The grounding grid also provides returning path for the ground fault current back to source neutrals. In addition, grounding grid provides low resistance in the loop for ground fault and enables protective relays to detect minimum ground faults.

The grounding grid of the substation typically consists of vertically driven ground rods, horizontally buried interconnecting grounding cables, connections to the metal parts of underground foundations, connections from the buried grid to metallic parts of surface structures and equipment, and connections to grounded system neutrals. Per Ohm's law, all the injected current to ground grid would result in ground potential rise difference (GPR) between grounded points in the substation and remote earth. Large GPR difference can exist between different grounded points within the substation if the station ground grid is not proper designed. The phase to ground fault current causes GPR, which poses the threat to station working personnel and equipment, is of interests in ground grid design.

IEEE Std. 80, Guide for Safety in AC Substation Grounding, is generally recognized as one of the most authoritative guides in substation design in North America. IEEE Std. 81 and IEEE Std 81.2-1991 provide procedures for measuring the earth resistivity, the resistance of the installed grounding system, the surface gradients, and the continuity of the grid conductors [1]. Other IEEE standards provide information on specific aspects of grounding [1], such as IEEE Std. 142 (Grounding of Industrial and Commercial Power Systems) on the practical aspects of grounding; IEEE Std. 367 (Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault) mainly for protection of telecommunication facilities; IEEE Std. 665 on the Guide for Generating Station Grounding.

The Figure 6 shows the current returning path of line close-in ground fault or ground fault in the vicinity of a substation. The magnitude and direction of ground current flow depend on the impedances of the various possible paths.

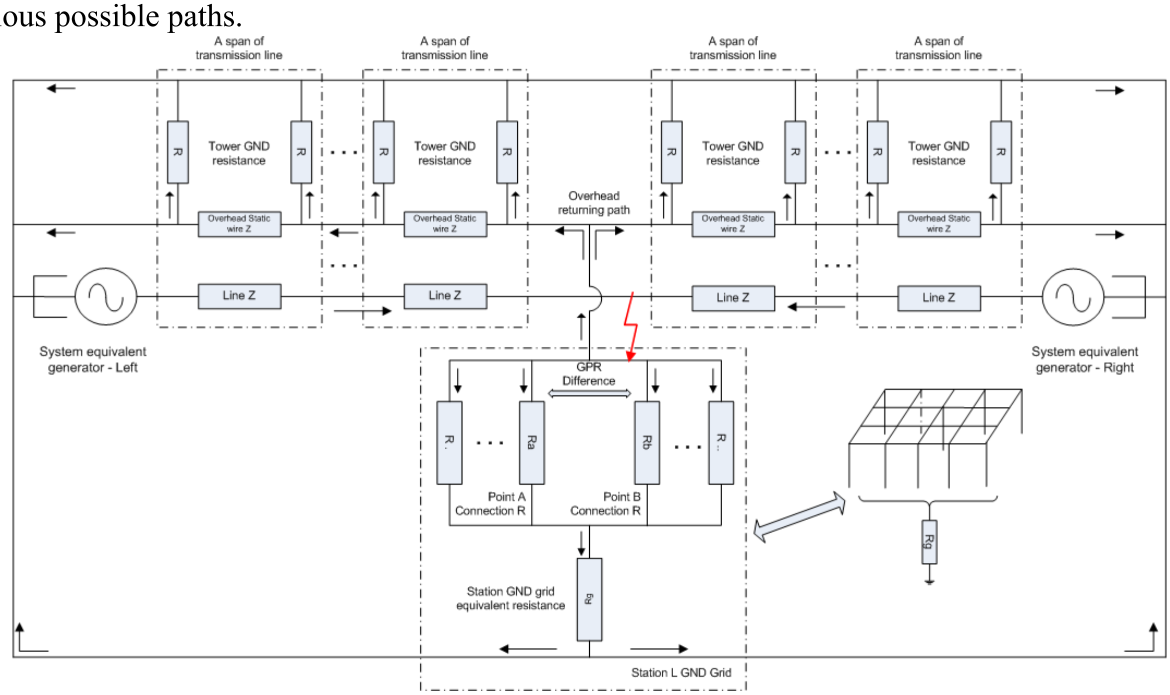

Figure 6: the ground fault current path through station L on September 2nd of 2011

From Figure 6, it can be seen that no ground source is available at station L and the total ground fault current is NOT equal to the ground grid current which uses earth as returning path to the source neutral. GPR in the substation is proportional to the magnitude of ground grid current and station grid equivalent resistance. The remaining portion of ground fault current uses overhead static wire to exit and doesn't result in GPR in the substation. The current is further diverted through several paralleled line tower footing resistance at individual line structure. It should also be noted that local grounding source at the station doesn't cause GPR for the local ground fault because that portion of fault current uses grounding grid as shortcut back to the local source neutral.

In this sense, the design engineer of the substation ground grid primarily put focus on the maximum amount of fault current that could be injected to the grounding grid to the remote earth.

Per IEEE Std. 80, the current split factor that not all fault current uses the earth as a returning path can be used to determine the maximum ground grid current at the substation. Annex C of IEEE Std. 80 (Graphical and approximate analysis of current division) provides guidance on how to calculate the split factor from graphs under different circumstances. This paper will not discuss this in details.

From station ground grid testing report, the resistance of station L ground grid is 0.5 Ω. There are 12 transmission lines connected to the station L. The typical footing resistance of transmission tower in that area is 15 Ω. Per curves to approximate split factor of Std. IEEE 80, the current split factor is approximately 30%, meaning 30% of the total fault current would go through station ground grid and 70% of fault current goes through overhead static wire.

VT secondary and relay AC circuit groundings.

In the substation, the secondary circuits of instrument transformer (CT & VT) are always bonded to the station main grounding grid for considerations of personnel safety and proper performance of relays. According to IEEE Std. C57.13.3 (The Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases), the instrument transformer secondary circuit, irrespective of the number of instrument transformer secondary windings connected to or in that circuit, should be connected to the station ground at only one point [2]. The two main reasons of having single point ground connection are to prevent GPR differences in the instrument transformer secondary circuit and facilitate the temporary removal and re-establishment of the ground connection.

The present practice of National Grid for VT/CT secondary grounding is to put safety ground with ground isolation facilities at the first point of application (switchboard or relay panel) in the instrument transformer secondary circuit. The circuit ground isolation provides convenient way of testing circuit insulation to ground.

The VT secondary circuit drawings of station L were checked. Multiple ground points were found in the voltage circuits as seen in Figure 7, one is at local junction box of VT secondary neutral and another is located at voltage synchronization circuits in relay panels. Substation L was designed and built in 1940s, it was before the publication of AIEE Application Guide No 52 in the year 1952, which was the forerunner of IEEE Std. C57.13.3. In the ensuing station upgrades, no attention has been paid to the multiple grounds in the VT secondary circuits until this event occurred in the September of 2011.

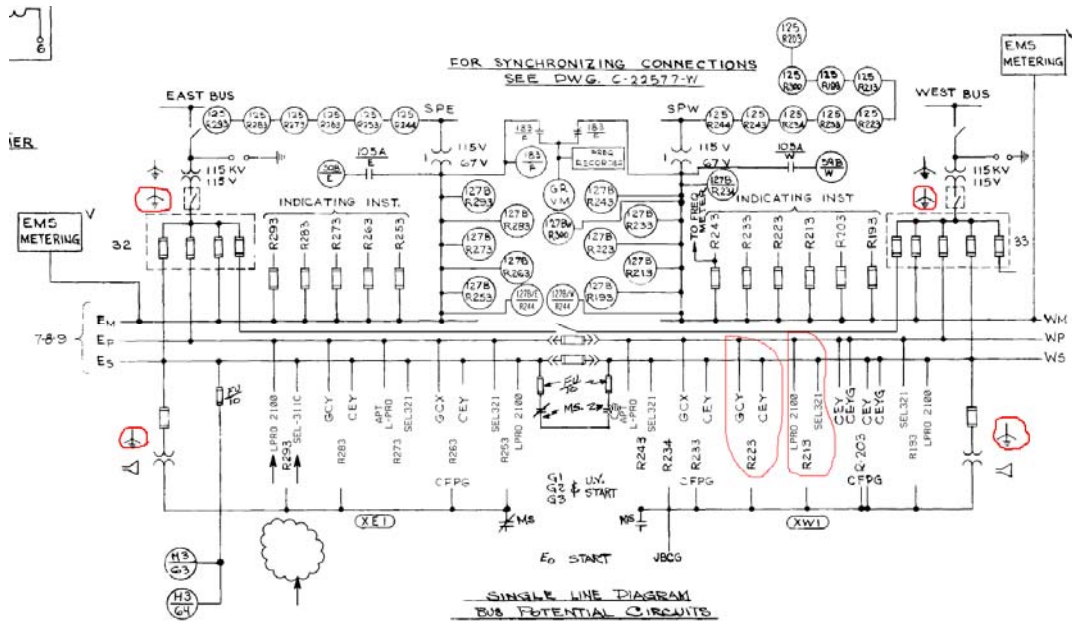

Figure 7: the bus PT connection diagram at station L

The ground grid, even when designed with a very low resistance, can't be considered as an equal-voltage surface. Substantial GPR differences may exist particularly in a large substation yard. When a close-in SLG fault occurred, high magnitude of ground current was injected into station grounding grid, resulting in ground potential rise (GPR) difference between different station locations. The magnitude of GPR difference depends on the magnitude of injected ground current, locations and the design of station grounding grid. The abnormal high magnitude secondary voltage with erroneous phase angle during this SLG fault was actually caused by GPR difference between PT local neutral grounding point and other grounding points at relay panels.

The vector diagram of VT secondary voltages for SLG fault with single grounding point and multiple grounding points are shown in Figure 8 & Figure 9 respectively.

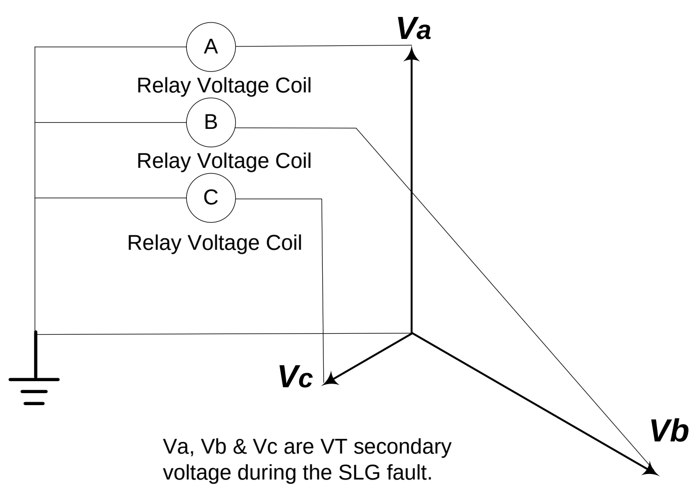

Figure 8: Single ground point on PT secondary circuit

For the single ground point in VT secondary circuit, the VT secondary voltage of faulted phase collapsed and GPR difference has no impacts on relay voltage measurement. The relay coils sense the true VT secondary voltages.

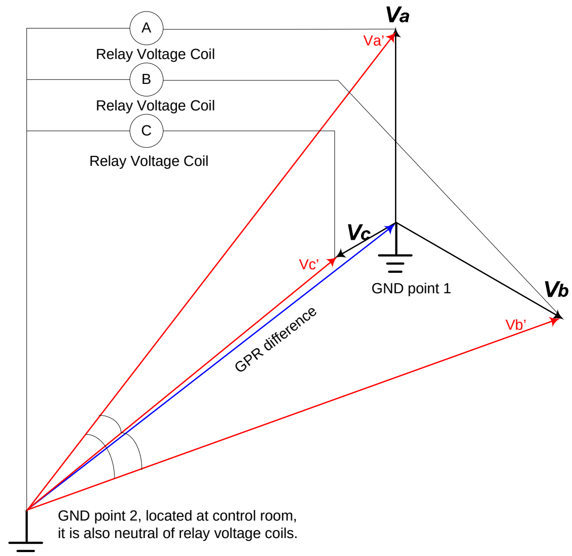

Figure 9: Multiple ground points on VT secondary circuit

The multiple ground points on VT secondary circuits introduce GPR difference between different locations into relay voltage measurements. This will be more pronounced when one ground point is at local VT junction box and other ground points at relay panels in the relay room. The voltage Va', Vb' & Vc' in Figure 9 are the resultant voltages of the VT secondary voltages superimposed with GPR difference during the fault. Those voltages are used by relays for distance calculations/measurements and can not reflect the actual faulted system parameters. This could also explain why all 3-phase voltages seen by relay were elevated and with erroneous phase angle shift during the fault.

Ground Potential Rise (GPR) and GPR difference at station L

The sources in the power system are assumed to be infinite and so strong that both magnitude and phase angle of the source remain unchanged during the fault. The fault loop circuit and its simplification are shown in Figure 10 below:

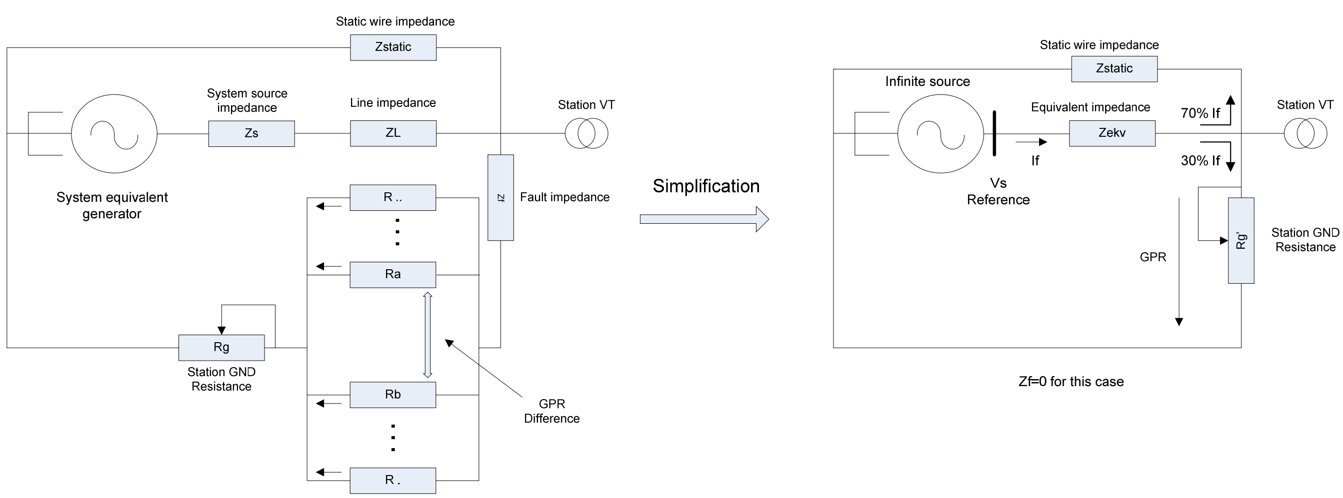

Figure 10, Fault current loop and GPR at Station L on September 2nd of 2011

For this particular case, the magnitude of VT secondary voltage for the faulted phase is the voltage drop across the fault impedance. It would be zero if the fault impedance is zero. The vector illustration of the simplified circuit is shown in Figure 11.

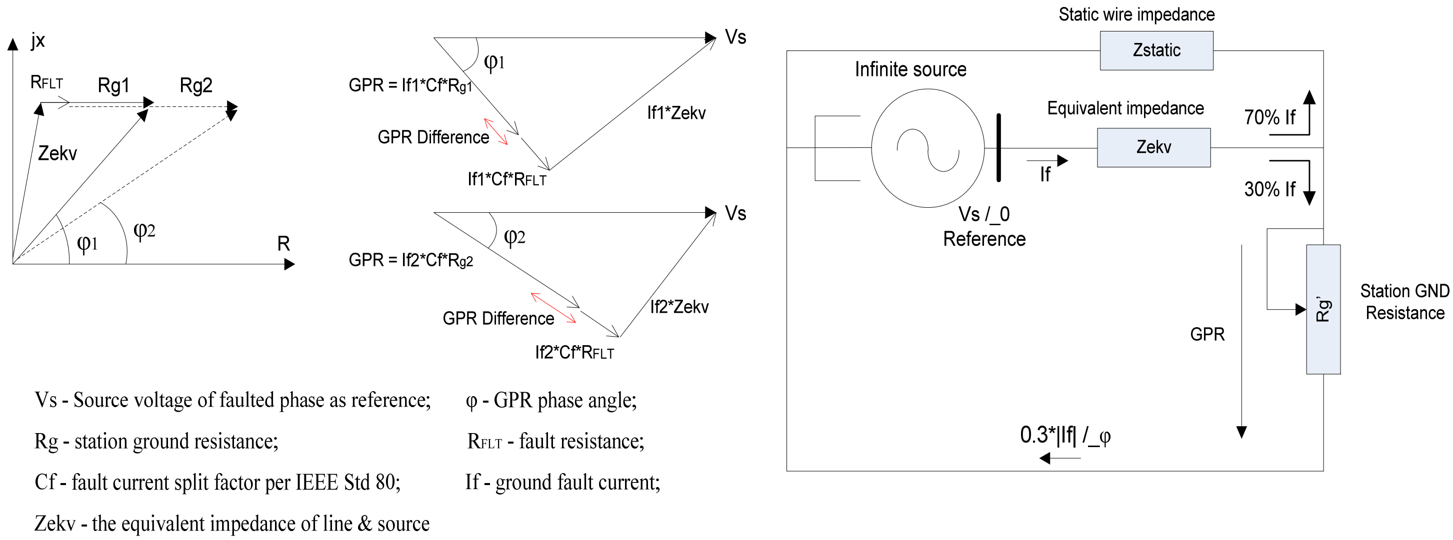

Figure 11 Station ground grid resistance and influence on GPR phase angle

From the voltage vector diagram, it can be derived that the angle of GPR or GPR difference and ground grid current is in phase. Large ground grid resistance would result in smaller phase angle if system voltage is used as a reference.

Per KVL and fault current split factor (0.3) from IEEE Std. 80, the following proximity equation is valid:

$$V_s \approx I_f * Z_{ekv} + 0.3 * I_f * R_g \text{ ----- (1)}$$

Where:

I_f is total fault current;

V_s is source voltage (reference);

R_g is station ground grid resistance;

Z_{ekv} is equivalent impedance of simplified circuit.

The mathematical expressions for the pre-fault voltages are given below:

$$Va = V_{VTA} * \sin(\omega t)$$

$$Vb = V_{VTB} * \sin(\omega t - 120^\circ)$$

$$Vc = V_{VTC} * \sin(\omega t + 120^\circ)$$

Where:

Va, Vb & Vc are voltage inputs to the relay;

V_{VTA}, V_{VTB}, V_{VTC} are VT secondary voltages.

Per relay records from Station L & M, the total fault current was approximately 15kA. The current injected into ground grid at Station L would be 5kA when considering 30% of split factor from IEEE Std. 80. Then the ground potential rise of Station L was 2500V.

From fault simulation program, the equivalent impedance of the power system is 0.31+ j2.34 Ω. The previous equation 1 can be re-written to:

$$Vs \approx If^*(Z_{ekv}+0.3^*R_g) = I_f^*(0.31+j2.34+0.3^*0.5) = I_f^*(0.46+j2.34) = I_f^*2.38\angle 78.87^\circ$$

Therefore the phase angle of GPR is -78.87˚ when using system voltage as a reference.

The voltage mathematical expressions for relay voltage inputs at station L can be written below:

$$Va=V_{VTA}^*\sin(\omega t) + V_{GPR\_D}^*(\omega t-\varphi)$$

$$Vb=V_{VTB}^*\sin(\omega t -120^\circ) + V_{GPR\_D}^*(\omega t-120^\circ- \varphi)$$

$$Vc=V_{VTC}^*\sin(\omega t +120^\circ) + V_{GPR\_D}^*(\omega t+120^\circ- \varphi)$$

Where:

Va, Vb & Vc are voltage inputs to the relay phase voltage coils;

V_{VTA}, V_{VTB}, V_{VTC} are VT secondary voltages;

φ is phase angle of GPR difference, it is 78.87˚ when the calculation follows IEEE Std. 80.

V_{GPR_D} is GPR difference magnitude between local VT neutral and protection panel in the control room. Since the ground fault at station L was close-in, the assumption of 3V (4.5% of nominal) for the magnitude of VT secondary voltage is reasonable. Using faulted phase voltage of relay records in Figure 2 as reference, the magnitude of GPR difference was approximately 170V.

The resultant voltage during the fault can be restored and manipulated in the time domain by using MS Excel. For the close-in single phase to ground fault at station L, the VT secondary voltage of the faulted and healthy phases are assumed to be 3V (4.5% of V_{LN}) and 64.5V (100% of V_{LN}) respectively as per previous discussion. Transients and DC offset are not considered for simplicity in the calculation. System 2 relay record of line L114 (in Figure 2) is used as reference, then the most proximity voltage waveform can be obtained by changing the phase angle of GPR difference (it is a simple error and trial method). The waveform is shown in the Figure 12 below, where the phase angle of GPR difference is 61.5˚. It verifies the voltage vector diagram in Figure 9 and also confirms the ground grid current split factor method from IEEE Std. 80 is well acceptable.

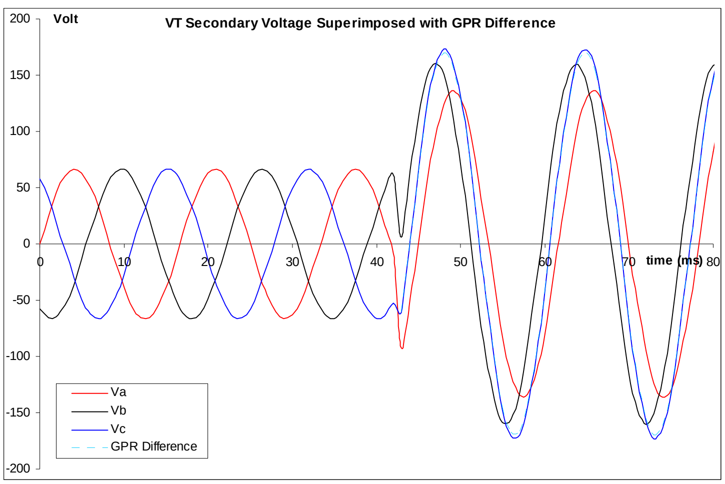

Figure 12: The calculated waveform of resultant voltage during line L114 fault at station L

Erroneous voltage waveform seen by relays at station L:

Why did system 1 relay of line L114 and system 2 relay of line L114 at station L have some issues on the voltage measurement? What caused the square voltage waveform as seen by digital relays from different manufacturers?

According to instruction manual of system 1 relay of line L114, the maximum measurable voltage without apparent distortion for relay internal PT is 2 times nominal voltage plus around 10% tolerance, which is around 152V rms. It has been confirmed with the manufacturer that the distorted wave shape is due to the saturation of the relay internal PT when high level voltage applied and the clipping is due to excessive input voltage beyond the A/D measurable limitation.

The instruction manual of system 2 relay of line L114 also indicates that the relay would not have any issue when up to 150V AC continuous line to neutral voltage is applied. However, the measurement errors would be present when excessive voltage is applied to the relay. Per Figure 4, it seems the margin of overvoltage capability of the relay from the manufacturer is +15%. The performance difference of L111 and L114 system 2 relays on overvoltage was mostly caused by individual difference.

Why there was no secondary voltage issue on May 15th of 2011 even though the same type of ground fault occurred on line L114? According to relay records, the fault location was in the middle of line and fault current magnitude was relatively low. Since there is no ground source at station L, the ground fault current using station L ground grid as returning path to power source neutral was much smaller than the close-in ground fault near station L on September 2nd of 2011. The ground fault current path is shown Figure 13 below. Therefore GPR or GPR difference was not that pronounced and the relay voltage measurement at station L was ok.

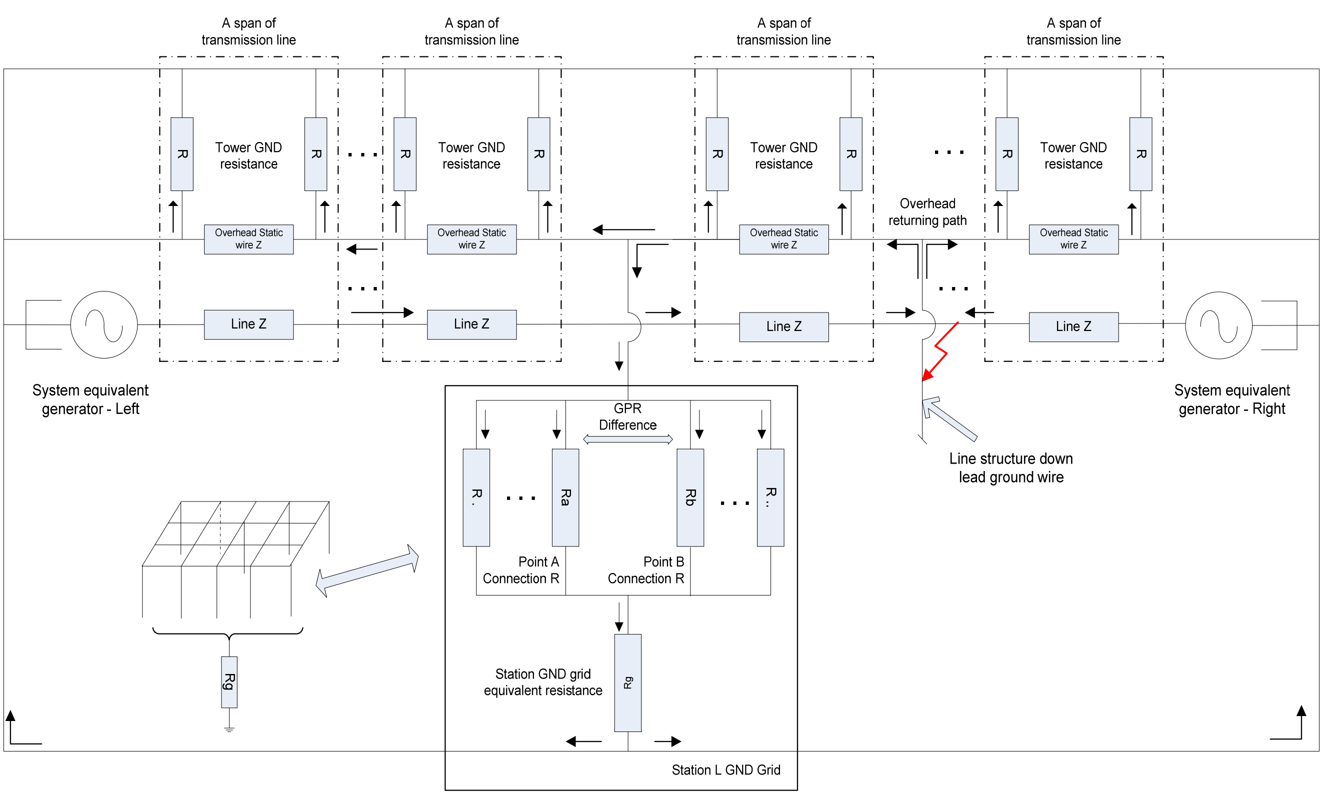

Figure 13: the ground fault current path through station L on May 15th of 2011

Misoperation of L114 Electromechanical (EM) relay at station L:

As discussion in the previous part, the actual voltages to relay voltage coils are the vector summation of VT secondary voltage and GPR difference between grounding locations of relay panel and VT secondary neutral. Due to the presence of GPR difference, not only the magnitudes, but also the phase angles of the voltages, which are to be used by protection and metering, are incorrect. Since distance relays require voltage inputs as polarization, the incorrect voltage information to the relay would definitely lead to improper operation. Therefore, it is the erroneous resultant voltage that caused L103 EM relay to misoperate on the reverse fault.

Relay records from Station M:

At station M, line L114 is protected by dual digital protection systems from the same manufacturer with different types. The line breaker R144 at station M was tripped almost in the mean time when a close-in ground fault occurred on line L114 near remote end. The relay fault locators of both relays indicated the fault was on the remote end, but the line was tripped by instantaneous protection elements. Did both relays of L114 at station M misoperate or have erroneous fault locator?

As per records of line L114 at station M shown in Figure 13, the relay was initially triggered by ground overcurrent element (51G) and zone 2 ground distance element (Z2G) asserted in 0.75-cycle. Due to the increment of fault current, the instantaneous ground overcurrent element (67N) asserted and issued the trip to line L114. It can be seen zone 1 ground distance element (Z1G) element asserted in approximately 1.5 cycles after the assertion of TRP relay word.

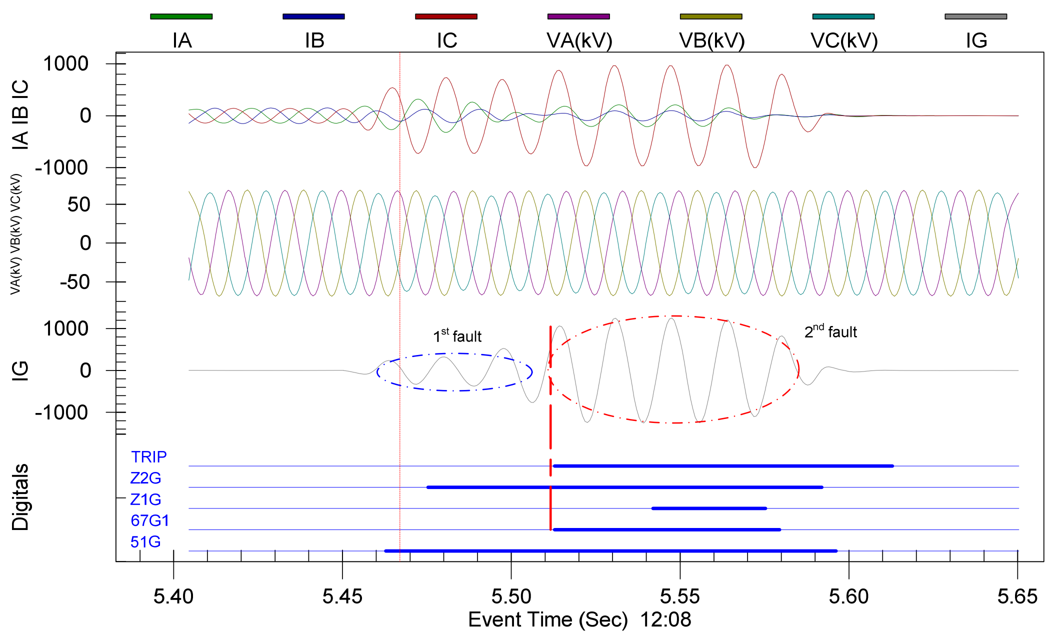

Figure 14: the system 1 relay record of Line L114 at station M on September 2nd of 2011

The fault simulations were performed in the fault short circuit program. The single phase ground fault was firstly set at station L or line remote end. In the simulation, 350A of ground current was contributed from station M through line L114, which matched the relay records (320A) and also explained why Z2G asserted. After carefully looking at the ground current of relay record, it can be observed that ground current of line L114 was continuous and suddenly jumped to 1200A in approximately 3.5-cycle after initial fault inception. The second fault location, which is 70% of the line from station M, was selected for the simultaneous fault simulation. The simulated results matched the relay records pretty well. From both relay records and fault simulation, it can be concluded that line L114 fault was of evolving nature with multiple points which occurred 2.5 cycles apart.

Why the relay of the line indicated the first fault location rather than the last one? This had been consulted with the relay manufacturer. The explanation from the manufacturer was that the fault location algorithm of the relay has a fairly complex algorithm for determining which currents and voltages to use in the estimate. The locator is not based on maximum fault current and does not use a fixed time frame, but chooses a time between the fault inception and expected breaker opening by checking for an estimate that has little variation.

Conclusions and Follow-up Action

It was concluded that the root cause of the misoperation of phase B zone 1 protection for line L103 at station L was due to the presence of incorrect voltage in the VT secondary circuit during the ground fault. The incorrect voltage, embodied in abnormal high magnitude in all 3-phase voltages with erroneous phase angle, was caused by multiple grounds in the VT secondary circuit. These abnormal voltages recorded by relays are actually not VT secondary voltages, but the vector summation of VT secondary voltage and GPR difference between different grounding locations of relay panel and local VT secondary neural. The clip voltage waveform of relay records was due to excessive voltage applied. The fault locator information from distance relay is for reference only because the algorithm of fault locator and distance calculation could be different.

Besides the grounding point at the relay panel, the additional grounding at local VT secondary neutral was identified and removed.

Reference:

[1] IEEE Std. 80 - Guide for Safety in AC Substation Grounding

[2] IEEE Std. C57.13.3 - The Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases

[3] Instruction manual of digital relays from manufacturers

Authors:

Song Ji is a lead senior engineer in the Department of Protection Policy and Support of National Grid, where he analyzes system disturbances on transmission and supply networks, develops & reviews protection related standards and applications. Song has more than 16 years experience in the power system studies, substation & power plant design, protection and control for utility and industrial systems ranging from 4.16 kV to 500 kV. Prior to joining National Grid, Song spent 4 years with WorleyParsons Canada as a power system specialist and 9 years with Henan Electric Power of China State Grid as a power system engineer. He received BSEE in power system from Zhengzhou University in China and a MSEE in power system from Royal Institute of Technology in Sweden. He is a member of IEEE and a registered professional engineer in Alberta Canada.

Yujie Irene Lu received a BSEE degree in Power Systems Engineering from Huazhong University of Science & Technology in China, and a MSEE in Electrical Engineering from Virginia Polytechnic Institute in Blacksburg, VA. Irene has been employed in Protection Engineering at National Grid since 1990. She is a principal engineer in the Department of Protection Policy and Support, where she analyzes system disturbances, performs system analysis for short circuit conditions, develops/revises protection and control system standards and guidelines, designs protection systems on a conceptual basis, specifies equipment and determines protection settings and logics. She has 20 year's experiences as a lead protection engineer on projects and worked on installation of major 345/115kV GIS transmission substations. Irene has represented the National Grid as a standing member of NPCC TFSP (Task Force on System Protection) and SP-7 (System Protection Misoperation Review working group) since 2011. Previously, Irene worked for the Department of Energy of China for 5 years. She is a member of IEEE and a registered professional engineer in MA. She received the 2010 Outstanding Engineer Award from the Boston Chapter of the IEEE Power and Energy Society in November 2010.