Back to Table of Contents

# WECC DISTURBANCES ILLUMINATE PROTECTION TRIBULATIONS

**Western Electricity Coordinating Council**
**Relay Work Group**

**32nd Annual Western Protective Relay Conference**
**October 25 – 27, 2005**
**Spokane, Washington**

# INTRODUCTION

The Western Electricity Coordinating Council Relay Work Group (WECC RWG) has produced this document to inform the protective engineering community about protective relay performance during past WECC disturbances with the intent to help them avoid the "mistakes of the past." This document will delve into select disturbances where the protective relay or special protection system performance was undesirable. Relevant details about the power system configuration, operating conditions, protective relay performance, and disturbance consequences will be provided. General analysis of the protective relay and special protection system performance will be provided along with recommendations for corrective action.

# BACKGROUND

The following are among the scope and responsibilities of the work group:

1) Analyze the performance of protective relay and special protection schemes including remedial action schemes following WECC disturbances, and make recommendations for corrective action. Prepare an annual disturbance analysis report and distribute it to the Operating Committee membership.
2) Provide technical input for WECC system disturbance reports. Participate in the preparation of detailed system disturbance reports.
3) Promote the interchange of system protection knowledge, experiences, and maintenance practices within the WECC.
4) Encourage manufacturers' work leading to the development and manufacture of improved protective relaying and monitoring devices.

The WECC RWG has been performing a detailed analysis of WECC system disturbances with an emphasis on improving the performance of protective relaying since 1980.

# ANALYSIS

The WECC RWG analyzed each disturbance to determine if the original categorization is correct. The WECC RWG paid particular attention to disturbances which involved protection systems and special protection systems (SPS). Special protection systems include remedial action systems (RAS) and other specialized relaying

## DEFINITION OF A SYSTEM DISTURBANCE

The definition of a disturbance is any occurrence similar to those described under Level 1 or Level 2, or any event requiring a DOE or NERC report.

LEVEL 1:

1) The occurrence of an interconnected system separation and/or system islanding, or
2) Unanticipated loss of generation equal to or greater than 2000 MW where such generation loss is **not** part of a larger event or **is** a precipitating factor of a larger event that will require a report.

LEVEL 2:

3) A system event that results in the loss of firm customer load for more than 15 minutes, as described below:
   a) Entities with a previous year recorded peak demand of more than 3000 MW shall report loss of firm loads equal to or greater than 300 MW, or
   b) All other entities shall report the loss of firm customer load that is equal to or greater than 200 MW or 50% of the system's total firm load, whichever is less, or
   c) Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system, or
4) Sustained voltage excursions, greater than one minute, equal to or greater than ± 10%, or
5) Major damage to power system components due to equipment failure or due to earthquakes, severe storms or other acts of nature or acts of sabotage, or
6) Frequency excursion, greater than or equal to ± 0.05 Hz, caused by unanticipated loss of load or generation.

## IMPACT ANALYSIS

For each disturbance reviewed, the action of the protection systems or special protection systems was categorized to determine its impact contribution to the severity of the disturbance.

The categories are:

1) Primary Cause: The protection system or special protection system directly caused the disturbance to occur.
2) Secondary Cause: The disturbance was caused by some other action. The protection system or special protection system operation had a major contribution toward the severity of the disturbance.
3) Minor Contribution: The disturbance was caused by some other action. The protection equipment or special protection equipment had only a minor contribution to the severity of the disturbance.
4) No Contribution: The protection equipment or special protection equipment action did not contribute to the disturbance. The equipment functioned properly.

## TROUBLE ANALYSIS

The WECC RWG analyzed each cause of trouble for the protection or SPS scheme. Each cause was categorized into one or more of the following groups:

1) Communications: Problem with the telecommunications channel, tone gear, etc.
2) Components: Failure of a part or module of a relay or a component relay.
3) Settings: Inappropriate relay setting, either calculated or applied.
4) Design: Design errors or inappropriate design of circuit.

5) Procedures: Improper procedures including problems caused by maintenance, test, and installation procedures. This can also include switching or operational procedures.

6) Scheme: Inappropriate protection scheme used.

## SECURITY vs. DEPENDABILITY

With the review of the 1994-1997 WECC Disturbances, the WECC RWG began categorizing system protection and special protection problems as either a security or dependability issue. For the purpose of this analysis, security issues are defined as a false or inappropriate trip and dependability as a failure to trip when required. Protection systems have traditionally been designed to include a high level of dependability. However, as the system is operated closer to its limits, system security is becoming a more important issue.

# DISTURBANCE SUMMARY

Table 1 and 2 below summarize protective relay and special protection system performance for 54 WECC system disturbances which occurred during the six year period from 1998 to 2003.

| Protective Relaying Summary | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **Total** |
| Disturbances | 11 | 10 | 7 | 8 | 12 | 6 | 54 |
| Primary Cause | 5 | 1 | 3 | 2 | 1 | 1 | 13 |
| Secondary Cause | 1 | 1 | 0 | 0 | 0 | 1 | 3 |
| Minor Contribution | 0 | 3 | 2 | 0 | 1 | 0 | 6 |
| No Contribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| No Problems | 5 | 5 | 2 | 6 | 10 | 4 | 32 |
| Security Problem | 4 | 4 | 3 | 2 | 0 | 1 | 14 |
| Dependability Prob. | 2 | 2 | 2 | 0 | 0 | 1 | 7 |
| Communications | 2 | 1 | 1 | 0 | 1 | 2 | 7 |
| Components | 1 | 3 | 0 | 2 | 0 | 0 | 6 |
| Settings | 1 | 0 | 3 | 2 | 3 | 2 | 11 |
| Design | 0 | 1 | 1 | 0 | 0 | 0 | 2 |
| Procedures | 7 | 3 | 1 | 0 | 0 | 1 | 12 |
| Scheme | 0 | 0 | 1 | 0 | 0 | 0 | 1 |

Table 1: Summary of Protective Relay Operations during Disturbances

| Special Protection Systems Summary | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **Total** |
| Disturbances | 11 | 10 | 7 | 8 | 12 | 6 | 54 |
| Primary Cause | 1 | 0 | 0 | 1 | 0 | 0 | 2 |
| Secondary Cause | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Minor Contribution | 0 | 0 | 0 | 2 | 0 | 0 | 2 |
| No Contribution | 0 | 0 | 0 | 0 | 1 | 0 | 1 |
| No Problems | 10 | 10 | 7 | 5 | 11 | 6 | 49 |
| Security Problem | 1 | 0 | 0 | 3 | 0 | 0 | 4 |
| Dependability Prob. | 0 | 0 | 0 | 0 | 1 | 0 | 1 |
| Communications | 0 | 0 | 0 | 0 | 1 | 0 | 1 |
| Components | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Settings | 0 | 0 | 0 | 2 | 0 | 0 | 2 |
| Design | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Procedures | 1 | 0 | 0 | 1 | 0 | 0 | 2 |
| Scheme | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Table 2: Summary of Special Protection System Operations during Disturbances

There were twenty-one protective relay problems and four special protection system problems revealed during these disturbances. Thirteen of these protective relay problems were the origin of the disturbance.
As identified in the table, security problems occur twice as often as dependability for protective relay systems. This is a result of the application of protection systems with a focus on dependability. This leads to the first discussion topic – Protection System Dependability.

# ANAYLSIS OF PROTECTIVE RELAY PERFORMANCE

## SUMMARY

Table 3 summarizes the protection system and SPS problems by category and division within each category.

| Relay Settings and Applications | |
|---|---|
| Calculation | Line overcurrent setting did not provide for line loadability |
| | Transformer backup setting did not provide for 150% of FOA |
| | Line setting did not account for line outage effect on fault current |
| | Line setting did not account for known current imbalance |
| | Instantaneous OC set too low |
| | Setting policy did not account for manufacturer product change |
| Configuration | Directional supervision not set |
| | Wrong settings group enabled |
| | Over extended reach zone 2 also enabled for time delayed trip |

| Relay Settings and Applications (Cont.) | |
|---|---|
| Application | Unsupervised sudden pressure relay |
| | Lack of Breaker Failure |
| | Lack of redundancy |
| | Lack of transformer backup protection |
| IPP | Generator settings non-compliant with WECC standards |
| | Over voltage |
| | Directional line relay at wrong sensitivity |
| | IPP configured sensitive alarm elements into trip output |
| | Reverse power |
| **Relay, Personnel and Equipment Failures** | |
| Relay | Sudden pressure relay |
| | Card failure allows permissive echo |
| Personnel | Bus protection out-of-service |
| | Trip test bus with other bus out-of-service |
| | Shorted out relay when new relay installed |
| | Contractor cut breaker failure relay circuit |
| | Battery alarm ignored |
| Equipment | Control voltage failure (tripped charger breaker) |
| | Selector switch failure |
| | Test switch flashover |
| | Wire insulation in cabinet door failed |
| | Breaker failure |
| **Communications Schemes** | |
| PLC | Permissive signal shorted by three phase fault |
| | Failed impedance matching transformer |
| | Improperly set line tuner arc gap |
| Current Differential | Telco-provided circuit delay exceeded relay compensation |
| POTT | Permissive echo during swing and low power factor |
| **Special Protection Systems** | |
| Personnel | Maintenance switches left open |
| | Programming modifications |
| | Testing initiates SPS |
| Equipment | One SPS out with communications card failure in backup |
| | SCADA UVLS did not respond in time |

Table 3: Classification of protection system and special protection system operations during disturbances

# PROTECTION SYSTEM DEPENDABILITY

The consequences of a failure of a protection system are emphasized when protection engineers are trained. From this training the engineers are in the continual battle with project managers to gain funding to provide a very robust protection system. In the quest to provide the optimal protection system, the engineer must keep in mind the one design concept that will undue all efforts to produce the desired dependability – the Single Point of Failure.

## Single Points of Failure

A few disturbances were initiated by single points of failure in the protective relay scheme. Two of these events will be reviewed in detail. The first place to start is the source of the relay scheme control power – the battery charger.

### Battery Charger Outage

An insulator on one of four transmission circuits failed near a substation on a tower carrying four circuits. This short circuit resulted in high fault current which caused the static wire to break and fall into the remaining lines. A tripped AC circuit breaker feeding the station battery bank resulted in low DC control voltage. This low voltage prevented the circuit breakers at the substation from operating. A relay technician tripped an autotransformer 13 seconds after hearing it make an unusually loud noise. Eleven transmission lines tripped remotely to isolate the fault in about one and one-half minutes. The prolonged time was due to long remote backup times, fault current redistribution, and line reclosing operations. This resulted in an interruption to the 26 distribution stations being supplied from the substation. This outage interrupted approximately 700 MW of load and about 850 MW of generation was tripped. Most of the transmission lines were restored in two and one-half hours and all loads were restored in about six and one-half hours.

The utility system control had received the battery charger No AC alarm and acknowledged the alarm, clearing it from the alarm screen, but had failed to notify operating personnel.

#### *Conclusion*

1) *In many cases the greatest dependability hazard to protective relaying systems is the DC control system.*
2) *Protection practices have relied on zone 3 relays to provide the necessary remote backup to protect for such an event. Protection engineers may consider removing zone 3 relaying from service to avoid the NERC zone 3 setting parameters. Implement the appropriate recommendations below before disabling protection philosophies that have proven themselves beneficial in the past.*

#### *Recommendation*

*Review company practices and procedures in the follow areas:*

1) *Evaluate DC control system dependability (this may be achieved through redundant chargers, redundant batteries, appropriate alarming, etc.)*
2) *Develop procedures for the maintenance of the DC control system.*

3) *Review existing infrastructure and present design practices to eliminate overloading system operations personnel (dispatcher) with nuisance alarms.*
4) *Add time delay to alarms that are intermittent.*
5) *Set priority levels on alarms.*
6) *Instruct system operations personnel on the significance of a battery or charger alarm.*

The second disturbance in this category was initiated by the last device in the relay scheme – the trip multiplier relay.

### Trip Multiplier Relay Failure

A phase-ground fault occurred a few miles from a station. Only one of the two breakers at the station opened as shown in Figure 1. A failed auxiliary relay prevented the breaker from operating and clearing the fault. When the auxiliary relay failed to operate, it also precluded the breaker failure protection from operating as shown in Figures 2 and 3. As a consequence of the breaker failure function not initiating, the only way to clear the fault was to open all sources to the station. Several lines connected to the station tripped by overreaching backup relaying functions. However, the autotransformers did not have backup relaying installed and were not able to isolate the fault. The protection systems on the lines feeding the auto-transformers were not designed to detect faults through the transformer. Twelve seconds later the phase-to-ground fault became a three phase fault. The fault was not cleared for almost 39 seconds. This caused a total of about 4600 MW of generation and 1000 MW of load to be tripped. All lines were restored to service within two and one-half hours and most generation was restored within three and one-half hours.

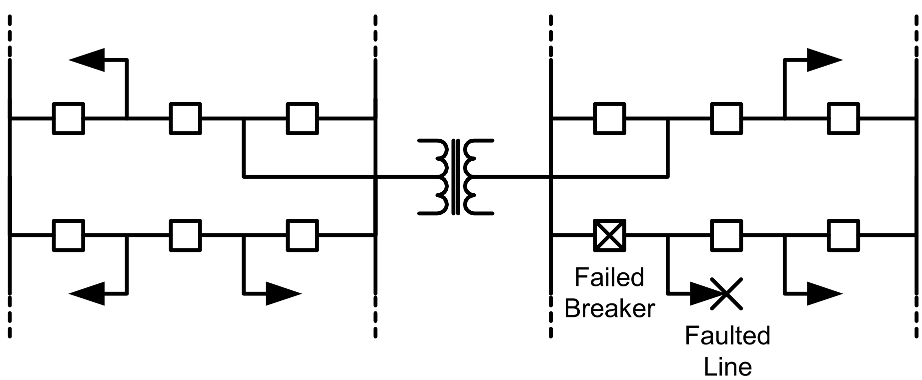


Figure 1. Station Configuration

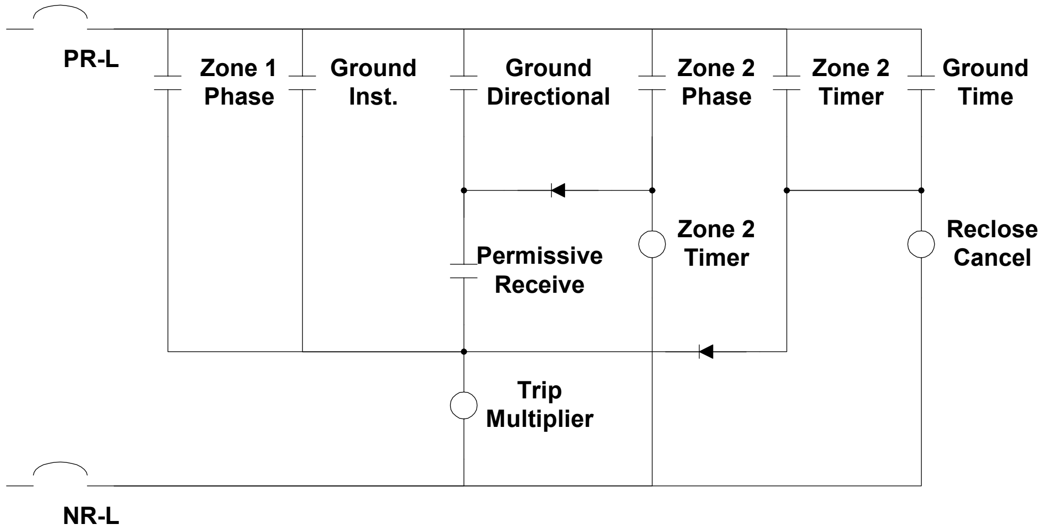

Figure 2. Line Protective Relay Logic

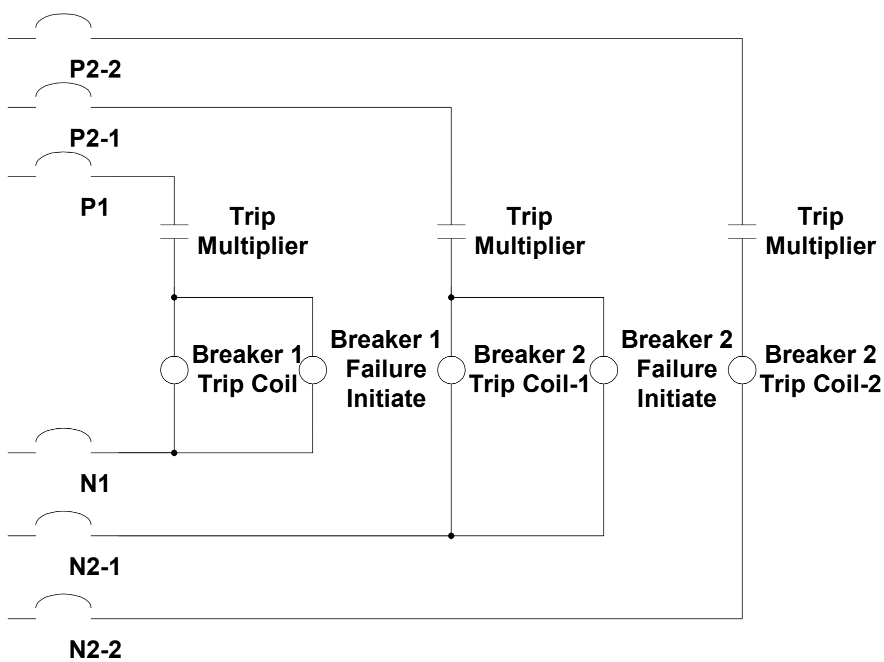

Figure 3. Trip Multiplier Relay Logic

## *Conclusion*

*The event described above occurred on a transmission line that was not considered critical to the operation of the bulk power system as lines with higher voltage and transfer capability were built. However, the consequences of a protection system failure resulted in a significant bulk power system disturbance.*

1) *When evaluating the application of redundant protection system, consider the redundancy from the battery charger through to the trip coil.*

2) *Breaker failure relaying does not require redundancy; however, the protection engineer should ensure that the ability to detect faults and initiate breaker failure is design so that it is not dependent on the breaker trip DC control voltage.*

### Recommendation

*Review existing infrastructure and present design practices to eliminate single points of failure. The following areas should be considered when redundancy of protection systems is required to meet NERC Reliability Standards:*

*Protective Relays – The transmission element will be protected by two relay systems ("System") where each is independently capable of performing the protective functions. The overall protection design should minimize the risk of both Systems being disabled simultaneously by a single event or condition*

1) *AC Current Inputs - The relay current sensing elements of each System are to be supplied by separate current transformer secondary windings.*
2) *AC Voltage Inputs – Where both Systems depend on voltage to operate the relay voltage sensing elements of each System are to be supplied by separate voltage transformer secondary windings from the potential devices.*
3) *DC Voltage – The DC control and power supply voltages (if required) for each System are to be supplied by separately fused circuits.*
4) *Communication Channels – Where communications-aided tripping is required to meet the system performance requirements, each System is to be supplied by an independent communications channel. The communications network carrying these channels must have redundancy as described in the WECC Communications Systems Performance Guide for Protective Relaying Applications.*
5) *Breaker Failure – The breaker failure function need not be duplicated; however, each System is to independently initiate the breaker failure protection function.*

## Relay Application

### Transformer backup

In the two events previously described the autotransformers were either tripped manually or did not trip at all. Transformers subjected to long durations of fault current will experience significant loss of insulation life due to both heat and mechanical stresses. In one event a single phase transformer failed twenty days later. This failure resulted in a fire that consumed five single phase-transformers as shown in Figure 4.

Figure 4. Consequences of a transformer failure

### *Conclusion*

*In many cases the transmission line protection systems applied to one voltage level cannot sense faults on the low voltage side of tie transformers. In such cases, transformer backup protection systems are the only method to clear faults where "Murphy" has uncovered protection system single points of failure.*

### *Recommendation*

*Review existing infrastructure and present design practices to ensure that transformer backup protection systems are installed where required.*

1) *At a minimum apply ground backup protection on the transformer (this may be installed on the neutral, on the tertiary, or by summation of the residual current on the high and low windings).*
2) *Additionally, apply phase backup overcurrent or distance protection with settings that conform to the NERC Loadability Parameters:*
   a) *System conditions, particularly during emergency operations, may make it necessary for transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not prematurely trip the transformers out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability criterion has been specifically developed not to interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.*

b) *The system operator actions may include manual removal of the transformer from service at any loading level in accordance with the transmission owner's operating policies and planned operating procedures, if doing so does not violate a system operating limit (SOL) or an interconnection reliability operating limit (IROL).*

c) *If the TPSO uses transformer **fault** protection relays, they will be reviewed to verify that the relay is not set to operate at or below the greater of:*

   i) *150% of the applicable maximum transformer nameplate rating, or*

   ii) *115% of the highest operator established emergency transformer rating.*

d) *Where applicable, the relay settings will be evaluated assuming the terminal voltage, at the relay potential device location, to be 85%, and a current phase angle of 30 degrees lagging.*

3) *Utilities should consider installing appropriate mitigation material at stations to limit the damage to adjacent transformer banks and associated cabling and DC equipment in the event of a catastrophic transformer failure.*

## Overcurrent Line Protection

1. A critical line was taken out-of-service during light loading hours for replacement of a gunshot insulator. Scheduled transfers were reduced so that the remaining three lines, each with a 126 MVA continuous and 151 MVA 30-minute overload rating, were loaded to about 340 MW. About one-half hour later, one of the three parallel lines experienced a single-line-to-ground fault for which two of the parallel lines tripped. The second line tripped due to an overly sensitive instantaneous directional ground overcurrent element. Five minutes later the third line tripped for a single-line-to-ground fault when the extreme loading caused a damaged conductor section to break. The 340 MW of flow transferred to another path and one minute later another line tripped by phase overcurrent. The phase overcurrent relay was applied for backup fault protection and set for 102% of the line thermal rating. This disturbance resulted in overloading and Operating Transfer Capacity (OTC) violation and there was a loss of about 10 MW of load for two hours.

### *Conclusion*

*Frequently poor protection application and settings are left undetected until a multi-contingency event occurs. Protection engineers should account for extreme conditions when determining protection application and settings.*

### *Recommendation*

*Review existing applications, settings and practices to ensure that line protection systems are:*

1) *Appropriate as changes in generating sources, transmission facilities, or operating conditions occur*

2) *Set in accordance with NERC Loadability Parameter*

*The line protection relays will be reviewed to verify that the relay is not set to trip at or below 150% of the maximum emergency rating defined above. The relay settings will be evaluated assuming the sensing voltage to be 85% and a current phase angle of 30 degrees lagging.*

2. One sunny Sunday afternoon a Cessna 310 contacted and severed the static line which fell into a phase conductor causing the line to trip. Three-quarters of a second later, two parallel lines feeding the station tripped when excessive neutral current, from a known steady state system imbalance, caused the ground backup protection to time out. A forth line tripped due to excessive harmonics caused by resonance between the line series capacitor, static VAR compensators, and HVDC valves. This sequence of events resulted in the tripping of 1600 MW of generation and the loss of 22 MW of load by underfrequency load shedding. Following the disturbance the protection engineers determined that the relays operated properly, however, they were not required as other redundant protection systems are able to detect all fault conditions.

#### Conclusion

*Known abnormal system conditions (e.g. steady-state imbalance, harmonic) should be taken into account when selecting and setting protective relays .*

#### Recommendation

*Review existing infrastructure and present design practices to ensure that line protection systems are applied with:*

1) *Ground protective relays settings accounting for system imbalances, changes in source impedance and significant mutual and zero sequence impedances.*
2) *All non-essential protection elements disabled to improve protection system security.*

## Communications Schemes

### Power Line Carrier CCTT

The initiating event for the disturbance was a single line to ground (SLG) fault on a line, about one mile from the station when a micro-burst went through a transmission corridor. The line is equipped with automatic re-closing, with about a 21-cycle delay. The fault was isolated through normal operation. About 20 cycles later the station breaker reclosed into the fault and tripped to lock-out. At this time and unknown to the dispatcher, the line had lost three structures, and produced a three-phase fault. Also due to loss of line structures, the power line carrier (PLC) communication channel was lost, making the primary carrier current transfer trip (CCTT) protection inoperative. The backup protection system had accidentally been disabled when modifications were made to the protection scheme. The line was test-charged from the station. Since the primary relaying was not functional and the back-up relay protection inoperative the fault was cleared by remote backup. All other lines feeding the station tripped and resulted in the loss of 250 MW of load. Service was restored to over 80 % of the customers within three hours.

### *Conclusion*

1) *The application of carrier current transfer trip (CCTT) may be an economical method to achieve redundant communications but it does not provide adequate dependability on its own.*
2) *Utility personnel (e.g. engineers, wirepersons, and technicians) require procedures to ensure that the modification of protection schemes do not result in the unintentional disconnection of other protective functions.*

### *Recommendation*

1) *Review existing infrastructure and present design practices to ensure that communications systems are installed where required and meet WECC Communications Systems Performance Guide for Protective Relaying Applications.*
2) *Direction comparison blocking (DCB) provides improved dependability over CCTT for PLC applications.*
3) *Review installation practices and procedures to ensure that they are consistent with the WECC Installation and Maintenance Guideline for Protective Relay Systems.*

### Permissive

A permissive overreaching transfer trip (POTT) scheme operated during a disturbance described above when the system experienced a low voltage and high reactive current flow as a result of delayed fault clearing. During this period of the disturbance, the generators were still exporting power but the area was absorbing reactive current, as the local area voltage was severely depressed as depicted in Figure 5. The relay system tripped on POTT echo logic when the impedance of the load condition entered the forward reaching zone 2 as shown in Figures 6 and 7.

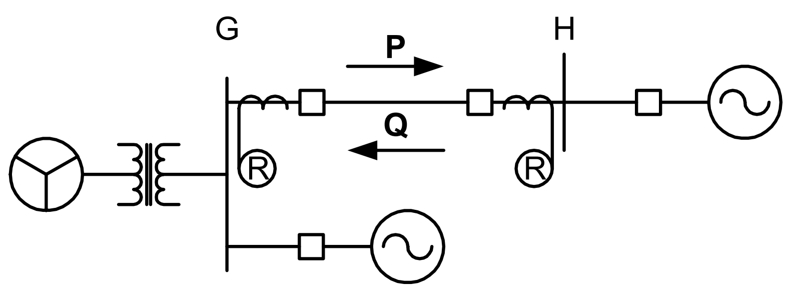


Figure 5. Power system configuration during extreme emergency loading

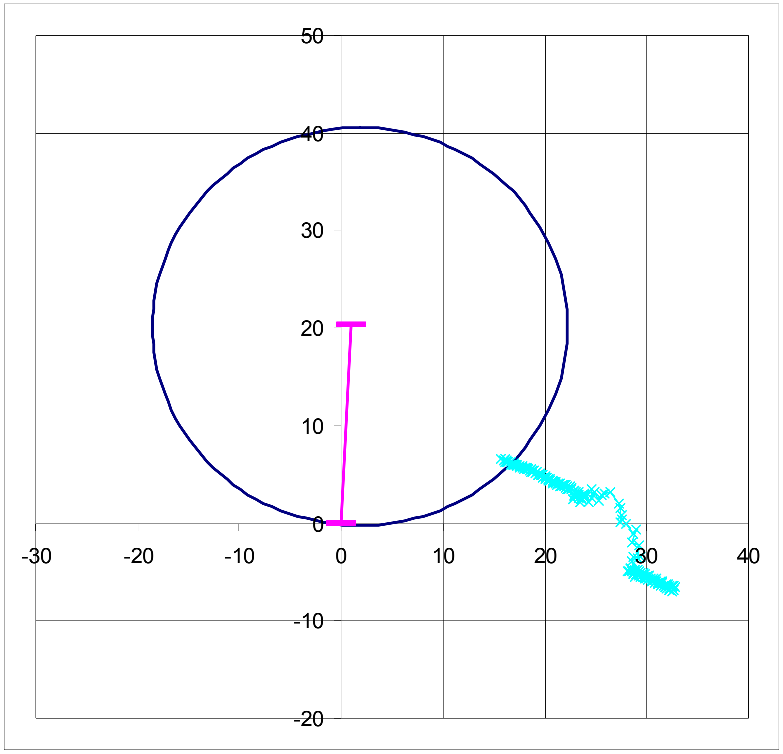

Figure 6. Impedance locus at G during emergency loading conditions

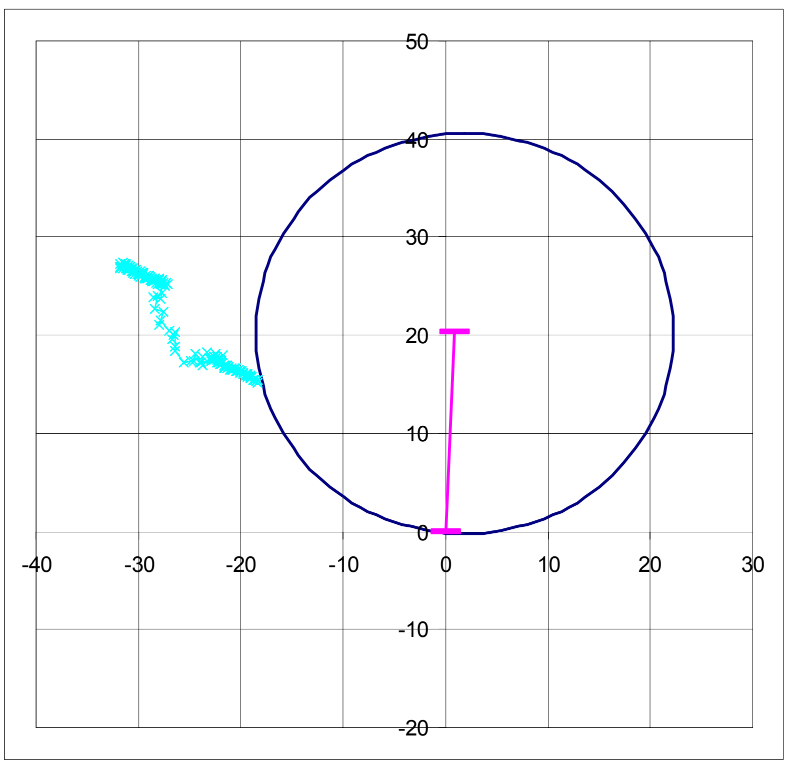

Figure 7. Impedance locus at H during emergency loading conditions

A second POTT scheme operated during a disturbance described above when the system experienced an out-of-step condition. The power swing went through a transmission line where power system blocking of the line protection was applied as shown in Figure 8. The line which experienced the power swing did not trip, however, the line between it and the generating plant tripped for the swing condition due to echo logic as Figures 9, through 12.

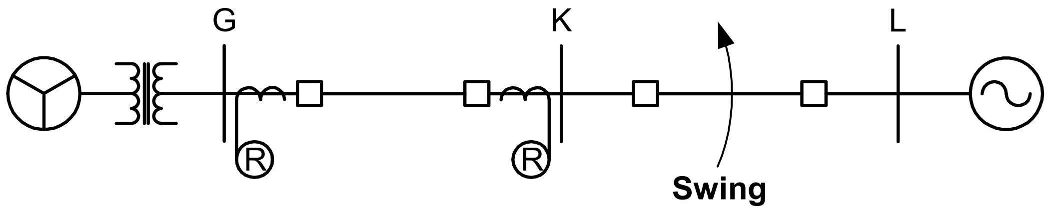


Figure 8. Power system configuration during out-of-step condition

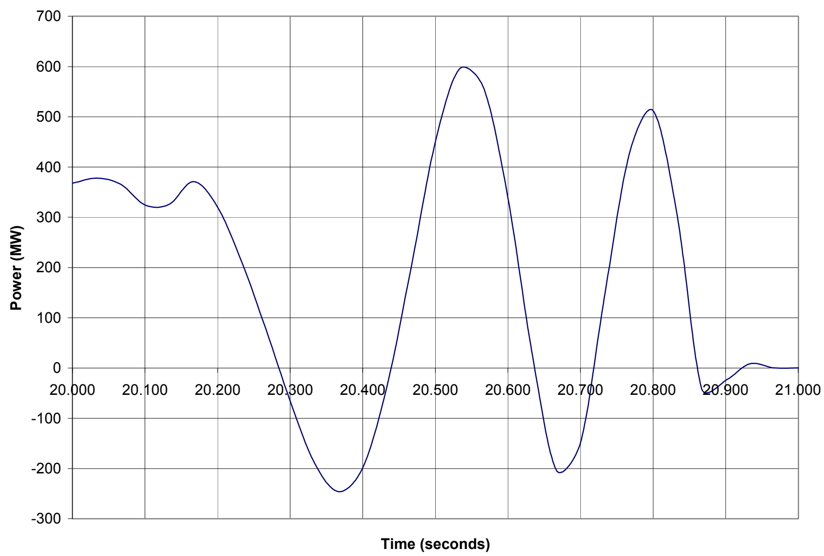


Figure 9. Power oscillations at G during out-of-step condition

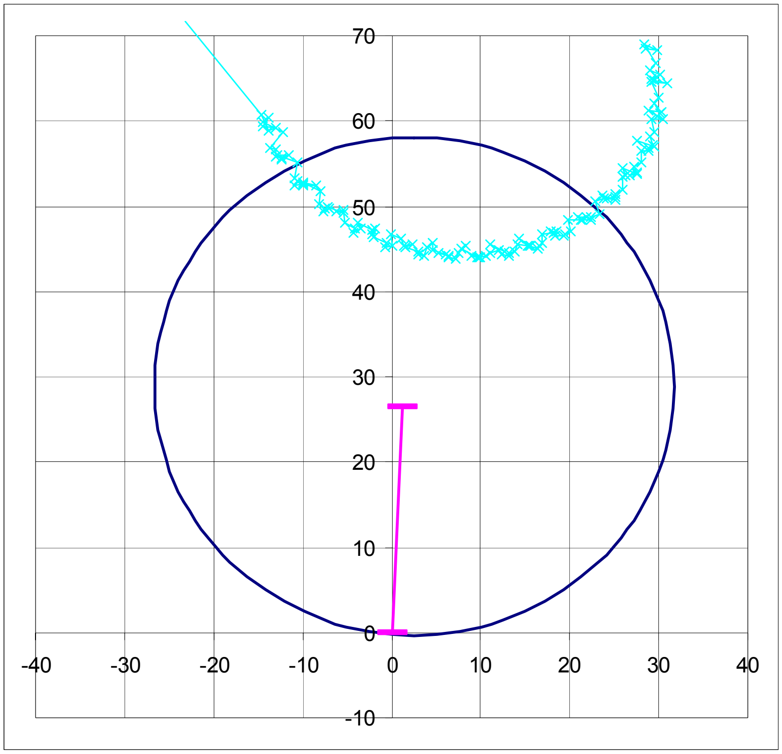


Figure 10. Impedance locus at G during out-of-step condition

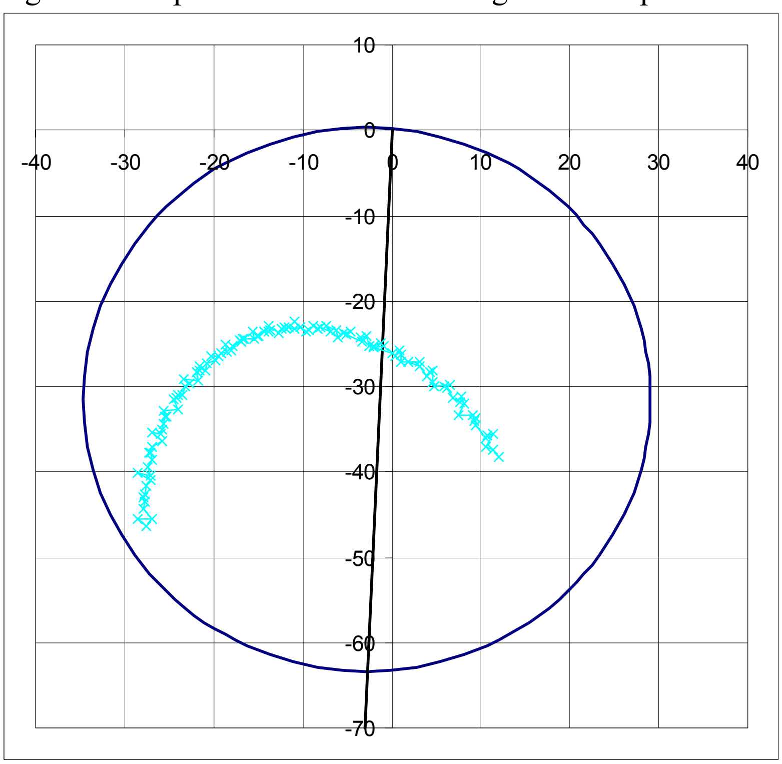


Figure 11. Impedance locus at K during out-of-step condition

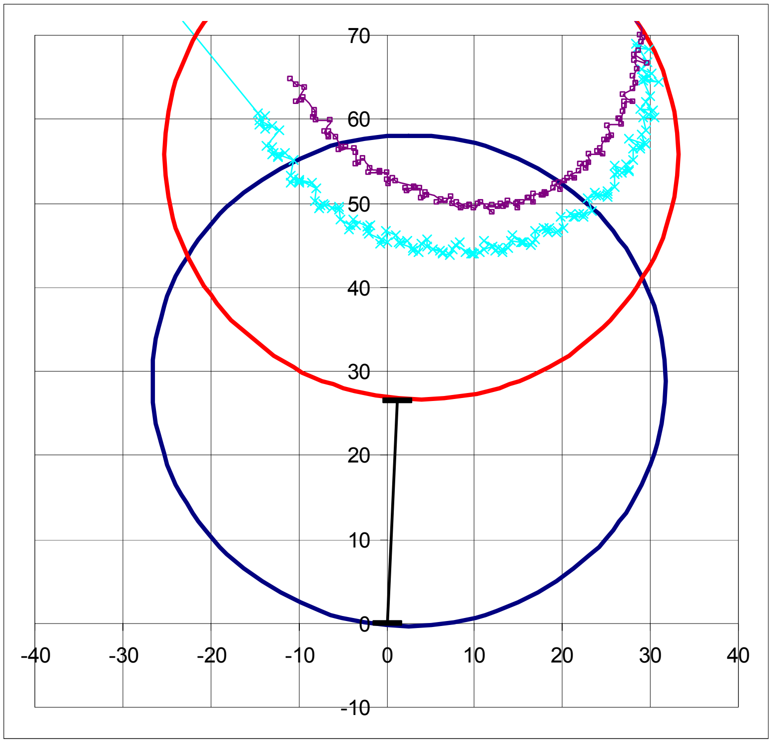

Figure 12. Impedance locus at G and K during out-of-step condition

### Conclusion

POTT schemes employing echo logic are not immune from tripping on emergency loading and swing conditions.

### Recommendation

1) *Review existing applications, settings and practices to ensure that line protection systems, including POTT and DCB schemes, are set in accordance with NERC Loadability Parameter*

   *The line protection relays will be reviewed to verify that the relay is not set to trip at or below 150% of the maximum emergency rating defined above. The relay settings will be evaluated assuming the sensing voltage to be 85% and a current phase angle of 30 degrees lagging.*

2) *Review POTT schemes for security of operation during extreme emergency loading and swing conditions. Determine whether the application requires echo-back keying. Consider implementing more secure echo logic by enabling it only during breaker-open conditions.*

3) *During relay qualification testing, test the protection system for performance during extreme emergency loading and swing conditions.*

4) *Review the application of power swing blocking and tripping. Transmission lines should not trip for out-of-line power swings. However, an action should be taken when an unstable swing passes through a transmission line. The action may be to*

*allow that line to trip or send a transfer trip to a more desirable tripping location (e.g. where the separation will provide a balance of generation and load).*

### Current Differential

A dump truck bed was raised to the point that caused a line to flash phase-to-ground just outside of a substation. Protective relays on the line correctly sensed the fault and opened the line at both ends. Simultaneously, another line tripped out due to a relay misoperation. Approximately two seconds later a combined cycle generator tripped due to loss of fuel and condensate pump failure, as well as operation of a reverse power relay. Almost concurrent with this trip, a HVDC terminal experienced a sequence of commutation failures and recoveries that eventually led to the commutation failure of the terminal. Three seconds later another unit tripped off line due to reverse power relay. Concurrently, the system experienced severe voltage degradation which caused a third line to trip and another line to trip on out-of-step. The local generation could not supply the system load and required reactive support resulting in a severe voltage collapse and subsequent loss of local generation and load. This resulted in the loss of 1150 MW of load, several transmission lines, and 300 MW of generation. It took six and one-half hours to restore service to all customers. The outage also caused damage to a generator exciter and a boiler-feed pump.

The primary cause of the disturbance was the simultaneous misoperation of two protection systems. One tripped incorrectly due to a setting error. The zone 1 distance element setting did not account for the series capacitor in the line section and therefore overreached the terminal whenever the series capacitor was in service. The other system misoperated due to a telecommunication link delay beyond the capability of the relay algorithm (the relay measures the channel delay and provides compensation for the delay). Installation testing did not reveal any time delay problems. It is assumed that there was an unreported change in commercial telecommunications circuits between the time of installation and the fault. The relay failed to provide proper alarming of a time delay outside of the relay capability.

#### *Conclusion*

The performance requirements of telecommunications links for current differential applications are the most stringent of any of the common communications aided tripping schemes. Modern protective relays have a greater ability to adapt to telecommunication channel performance variation but even modern relays have their limitations.

#### *Recommendation*

*Review existing infrastructure and present design practices to ensure that communications systems are installed where required and meet WECC Communications Systems Performance Guide for Protective Relaying Applications.*

*Changes to the communications system post-relay installation should be communicated to the relay engineers. Communication engineers should ensure that they meet the guidelines set forth in the WECC RWG/TELWG Communications System Performance Guide for Protective Relaying Applications.*

## Relay Settings

### Setting revisions

#### *Conclusion*

The relay misoperations described above came about because an incorrect version of the settings was loaded into the relay. The utility had the correct settings applied to the relay during the protection system qualification testing, but an earlier version of the settings was loaded when the relay system was put into service.

#### *Recommendation*

*Review existing installation practices and procedures to ensure that they are consistent with the WECC Installation and Maintenance Guideline for Protective Relay Systems. Protection engineers should be aware of the complications of multiple versions of settings files and establish procedures to manage settings files.*

# ANALYSIS OF SPECIAL PROTECTION SYSTEM PERFORMANCE

Between 1998 and 2003, there were five events where special protection schemes (SPS) performed improperly. These events are separated into procedural and software errors.

### Procedural Errors

Personnel opened switches to a SCADA RTU while reconfiguring the RTU. When they restored the SCADA RTU to service they left the switches in the open position. The SCADA RTU sent incorrect breaker position indications to the SPS line loss logic controller which then began appropriate action for the incorrect line loss indications.

A system operator followed the standard procedure for placing a phase shifting transformer in service by closing and opening motor operated switches via SCADA. The operator received appropriate open and closed indication of the switches and proceeded to open the breakers to complete the switching. However, one of the switches was only a quarter of the way open and flashed over when the breaker was opened. All three blades melted and initiated differential tripping in of the phase shifter. Afterward, the phase shifter was isolated by switches & tagged. The follow day, substation mechanics began inspection of the switch and mechanism. They decoupled the mechanism from the switch and began exercising the mechanism through its open and close positions. The position indication of this switch mechanism along with the position indication from other breakers and switched in the station resulted in initiating a load shed scheme that tripped 270 MW of load.

#### *Conclusion*

The SPS events described above were all caused by personnel performing their functions without the knowledge of how their actions would impact a SPS and ultimately trip a significant number of customers.

### *Recommendation*

*Utility personnel should review and strengthen the procedures for isolation and maintenance of SPS. Clear identification of all devices that provide input to SPS are critical to avoid false operations.*

### Software Errors

A system programmer making modifications to a substation RTU database entered the parameters in the wrong table which resulted in shedding 240MW of load.

A system analyst/programmer making modification to a load shed scheme initiated the scheme and shed 200MW of load.

One SPS employs redundant computers to monitor and control pairs of generators. The SPS has provisions to allow plant operators to identify the preferred generators to trip. The SPS algorithm allowed a different set of preferences on each of the SPS computers. The result was the possibility that each computer would process a trip to a different machine resulting in over tripping for a given system event. Of course, this happened and tripped 2000 MW of generation.

This same SPS tripped two units and followed with tripping a third generator later. The SPS computer algorithm to determine the optimal generators to trip based on unit status, unit loading and operator preferred trip settings. A simple mistake of declaring a variable as unsigned when it should have been declared signed resulted generator over trip. The SPS programming was corrected and tested. However, during this testing, another problem was discovered in the algorithm which could result in over tripping. This too was corrected and tested.

### Conclusion

SCADA systems are an appropriate technology for implementing some SPS. However, SCADA system masters and RTU's are continually being updated and the SPS are subject to corruption if appropriate procedures are not in place to protect the integrity of the SPS. Finally, as Microsoft will confirm, "undocumented features" are always lurking in computer code.

***Recommendation***

*Special operating and maintenance procedures need to be established for SCADA systems, particularly for substation RTUs, when they are used as part of a SPS. When implementing SPS, protection engineers must balance economy, simplicity, robustness, security and dependability.*

## CONCLUSION

A review of WECC system disturbances has illuminated the consequences of failures in protection system dependability and security. While the protection engineers have always strived to assure protection system dependability, security problems have contributed to disturbances twice as often as dependability issues. Additionally, the consequences of a lack of security rival those for a failure in dependability.

Consider a review existing facilities and present design practices to determine whether they are compliant with the past NERC Planning Standards. This will help prepare for compliance with upcoming NERC Reliability Standards. Take the time to assess the dependability of protection systems focusing on: DC control reliability, single-points-of-failure, transformer backup and communications system availability. Once this is completed, review the schemes and practices for security, focusing on: meeting NERC line loadability parameters including communications-aided tripping scheme operation for emergency loading and swings conditions. Also, question the practices for out-of-step protection of the power system. Coordinate with planning and operations to evaluate where to block and trip. Solely implementing swing blocking on all line does not protect the system, while allowing all lines to trip may be just as detrimental.

SCADA systems are the nucleus of controlling the power system. The SCADA hardware continues to provide more and more functionality. Protection engineers must work closely with operations to help them manage and determine what action to take for station alarms. The dependability of the power system rests on the operators, protection systems, and SPS. Protection engineers must provide operations with usable information on the status and capability of protection system, configure protection system so they allow operations 15 minutes to take corrective action during system emergencies, and provide reliable (secure and dependable) SPS as a back stop when events destabilize the power system.

# REFERENCES


WECC RWG/TELWG Communications Systems Performance Guide for Protective Relaying Applications
http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=115

WECC RWG Installation and Maintenance Guide
http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=115

Relay Loadability Exceptions Document (November 2004)
http://www.nerc.com/~filez/spctf.html


Back to Table of Contents