Operating Guides Revision Request

OGRR Number		OGRR Title	CREZ Facility Protection and Control Requirements
Date Posted			

Operating Guides (OG) Section(s) Requiring Revision **(Include Section No. and Title)**	ERCOT Operating Guides Section 7: Disturbance Monitoring and System Protection
Protocol Section(s) Requiring Revision, if any	None
Requested Resolution **(Normal or Urgent, and justification for Urgent status)**	**Urgent** – Requested revision resolution is important to CREZ facility protection and control design, installation, and schedule.
Revision Description	Revision to Section 7 is providing more stringent protection and control requirements for all new or rehabilitated CREZ facilities.
Reason for Revision	Revision to Section 7 is to provide requirements for the protection and control for the CREZ transmission system that supports the transfer of renewable energy reliably from remote areas to large load centers. These revisions to Section 7 are aimed at meeting the voltage curve described in NERC Reliability Standard PRC-024.
Overall Market Benefit	The reliable transmission of renewable energy sources across ERCOT promotes environmental conservation and stable power grid capable of supporting the Texas commerce reliably.
Overall Market Impact	The lack of properly designed protection and control for CREZ facilities will unnecessarily reduce ERCOT power system stability while maximizing the utilization of renewable energy sources.
Consumer Impact	Protection and Control usually represents approximately 10% or less of the cost of the main power system element installation. Providing proper protection and control to maximize the availability of the CREZ transmission facilities to support stable utilization of renewable energy sources is priceless at minimal real cost. Consumers will see reduced costs due to increased transmission reliability with some potential that increased capital cost of complying with the standard will be passed on to consumers

Quantitative Impacts and Benefits			
Assumptions	**1**	***Renewable energy sources usually lack the inertia to provide the same stability capability of the large coal or nuclear power plants. The CREZ transmission projects represent facilities that will remain in-service for many decades with each protection and control system having an average life span of 20 – 30 years. For the CREZ facilities to eventually maximize renewable energy sources without premature replacement of the first protection and control schemes the requested revisions to section 7 needs to be adopted.***	
	2	***Dependencies on other projects or other timing requirements***	
	3	***Increased reliability from properly designed protection and controls***	
	4	***Removes Ambiguity***	
Market Cost		**Impact Area**	**Monetary Impact**

	1	*Unknown*	
	2		
	3		
	4		
Market Benefit		**Impact Area**	**Monetary Impact**
	1	*Better documentation for Operational Analysis and Root Cause Analysis*	*Less generation for frequency and low voltage control*
	2	*Enhanced Reliability*	*Fewer Outages 1- 30 min outage per year*
	3	*Reduced congestion cost*	*0.01% reduction in total congestion cost*
	4		
	5		
Additional Qualitative Information	1	*System reliability will be greater resulting in additional revenue for the generators since outages should be reduced*	
	2	*Maintain system reliability as new generators are added to the ERCOT System.*	
	3	*Ability to add new renewable resources more effectively.*	
	4		
Other Comments	1	*Minimal impact to ERCOT systems impacts*	
	2		
	3		
	4		

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7 Disturbance Monitoring and System Protection

7.1 Disturbance Monitoring Requirements

7.1.1 Introduction

Disturbance monitoring is necessary to determine:

- The performance of the ERCOT system,
- The effectiveness of protective relaying systems,
- Verify ERCOT system models, and
- Determine the causes of ERCOT system disturbances (unwanted trips, faults, and protective relay system actions).

To ensure that adequate data is available for these activities, the disturbance monitoring requirements and procedures discussed in this document have been established by ERCOT for Facility Owners in the ERCOT system.

Disturbance monitoring equipment includes digital fault recorders (DFRs), certain protective relays with fault recording capability, and dynamic disturbance recorders (DDRs). Sequence-of-event recorders (SERs), although considered equipment to monitor disturbances, are not preferred devices, as they provide limited information. SERs have been replaced by digital fault recorders and microprocessor-based protective relays.

A yearly review of this document should be completed to insure compliance with all the NERC Reliability Standards

7.1.2 Fault Recording Equipment

Fault recording equipment includes digital fault recorders (DFRs) and protective relays with fault recording capability that meet the triggering requirements below. Fault recording equipment required by these Operating Guides shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (17 millisecond) timing accuracy and performance.

7.1.2.1 Triggering Requirements

Fault recording equipment triggering must occur for system voltage magnitude and current magnitude disturbances (delta V and delta I) without requiring any circuit breaker operations or trip outputs from protective relay systems. Triggering by additional methods is acceptable. Triggering shall be adjusted to operate for faults in the area to be monitored, which should overlap into the area of coverage of adjacent fault recorders.

7.1.2.2 Location Requirements

The location criteria below shall apply to equipment operated at or above 100 kV. The Facility Owner, whether registered as a TDSP or Resource Entity, shall install fault-recording equipment at the following facilities, at a minimum:

Deleted: fault recording

a. Interconnections to other Regions (i.e. outside ERCOT).

b. Switching stations where electrical transfers of equipment can be made between ERCOT and another Region.

c. Switching stations having three or more non-radial 345 kV line terminals. If a switching station is one bus removed from a station with a larger number of line terminals, then the fault recorder shall be located at the larger station and not required at the smaller station.

d. Switching stations that are more than one circuit breaker-controlled bus away from a fault recorder and have five or more non-radial line terminals.

e. For the purpose of evaluating #c. and #d. in this section, autotransformer or generating capacity totaling 150 MVA or greater (based upon minimum nameplate rating upon which transformer impedance is stated, i.e., base rating) shall constitute a non-radial line terminal at the highest voltage level to which it is directly connected.

f. All generating station switchyards connected to the ERCOT System with an aggregated generating capacity above 100 MVA or the remote line terminals of each generating station switchyard.

All fault recording equipment shall be either DFR's or fault recording protective relays

7.1.2.3 Data Recording Requirements

The following quantities must be recorded for equipment operating at 100 kV or above at facilities where fault recording equipment is required:

a. Two sets of voltages for breaker-and-a-half and ring bus substation configurations. One set of voltages for each bus in other substation configurations. A set of voltages shall consist of each phase voltage waveform.

Deleted: and the residual voltage waveform.

b. For all lines, neutral (residual) current waveform.

c. Circuit breaker status.

d. Circuit breaker trip circuit status.

e. Date and time stamp (CST).

For all new or upgraded fault recorder installations, additional items must also be recorded, as follows:

f. For all autotransformers, current waveform for three phases and either neutral / residual current waveform or current waveform in delta windings.

g. For all lines, two phase current waveforms.

h. Status – carrier transmitter control, i.e. start, stop, keying.

i. Status – carrier received.

7.1.2.4 Data Retention and Reporting Requirements

The Facility Owner shall store all recorded fault data for at least a two-year period. This data shall be stored in the form of a computer file or files.

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Facility Owners shall provide fault recordings to ERCOT or NERC upon their request, within five Business Days, along with channel identification and scaling information to allow analysis of the recordings. Fault recordings shall be shared between Facility Owners, upon their request, for the analysis of system disturbances.

Data submissions shall be COMTRADE fault recordings (.cfg and .dat files) and one or more identification files that associate the COMTRADE recordings with system disturbances and ERCOT short circuit database bus numbers. The identification file shall be a Microsoft Excel spreadsheet or comma delimited ASCII text that can be read into a Microsoft Excel spreadsheet. For this file, the data fields to be reported for each record, in the following order, are:

REPORTING ENTITY

Faulted Circuit	**Circuit or Bus (1, 2, A, B, N, S, etc.)**
From Bus (ERCOT short circuit database bus number)	
	To Bus (ERCOT short circuit database bus number)
Nominal Voltage of Faulted Branch or Bus (kV)	
Physical Fault Location in Percent from "From Bus" (if physical location found, i.e. not calculated location)	
	Date (CST, MM/DD/YYYY)
	Time (CST, HH:MM:SS, 24 hour format)
	Cause Code
Fault Recorder Data	**Circuit (1, 2, A, B, N, S, etc.)**
From Bus – Recorder Location (ERCOT short circuit database bus number)	
	To Bus – Monitored branch (ERCOT short circuit database bus number)
	Nominal Voltage of Monitored Branch (kV)
	Measured Current Magnitude (primary value in RMS amperes)
	Recorded Fault Duration (cycles)
	Fault Type (using reporting entity's phase designations – AB, CG, etc.)
Optional Comments (40 char. max.)	

When multiple recordings exist for a single event, data from the best recording (usually the closest recorder) is required.

ERCOT shall compile a summary list of all available 345 kV fault recordings annually based on each Facility Owner's submitted data. This summary shall contain for each recording the date, time, fault recorder owner, fault recorder location, the primary system element recorded, and an optional use comment field. This summary shall be available to any ERCOT Member upon their request. Record summaries will be retained by ERCOT for a minimum of three years.

7.1.2.5 Maintenance and Testing Requirements

Facility Owners shall maintain and test their Fault recording equipment as follows:

- In accordance with the manufacturer's recommendations.
- Calibration of the analog (waveform) channels shall be performed at installation and when records from the equipment indicate a calibration problem. Calibration can be monitored through the analysis and correlation of fault records with system models and the records of other fault recorders in the area.
- Fault recording equipment must be operationally tested at least annually to ensure that the equipment is functional. Acceptable tests are the production of a manually triggered record (remotely or at the device), or automatic record production due to a power system disturbance.

7.1.3 Dynamic Disturbance Recording Equipment

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7.1.4 Equipment Reporting Requirements

Facility Owners shall maintain a current database summarizing their disturbance monitoring equipment installations.

The database shall include installation location, type of equipment, make and model of equipment, operational status, a listing of the major equipment being monitored and the date the equipment was last tested. This database shall be submitted to ERCOT annually, by October 31. Additionally, a complete list of all monitored points at each installation shall be maintained by Facility Owners and provided, when requested specifically by ERCOT or NERC, within 30 days.

ERCOT shall maintain a comprehensive database of all Facility Owner's disturbance monitor equipment submittals, updated annually.

7.1.5 Review Process

ERCOT shall review fault recorder and disturbance recorder locations for compliance and adequacy when significant changes are made to the ERCOT system or at least every five years.

7.2 System Protective Relaying

7.2.1 Introduction

The satisfactory operation of the ERCOT System (equipment operated above 60 kV), especially under abnormal conditions, is greatly influenced by protective relay system.

Protective relay systems are defined as the total combination of:

- The protective relays,
- Associated communications system,
- Voltage and current sensing devices, and,
- The dc system up to the terminals in the circuit breaker.

Although relaying of tie points between Facility Owners is of primary concern to the ERCOT System, internal protective relay system often directly, or indirectly, affects the adjacent area also. Facility Owners are those entities owning facilities in the ERCOT System. Facility Owners have an obligation to implement relay application, operation, and preventive maintenance criteria that assure the highest practicable reliability and availability of service to the ultimate power consumers of the concerned area and neighboring areas. Protective relay system of individual Facility Owners shall not adversely affect the stability of ERCOT System interconnections. Additional minimum protective relay system requirements are outlined in NERC Planning and Reliability Standards.

These objectives and design practices shall apply to all new protective relay system applied at 60 kV and above unless otherwise specified. It is recognized that there may be portions of the existing ERCOT System that do not meet these objectives. It is the responsibility of individual Facility Owners to assess the protective relay system at these locations and to make any modifications that they deem necessary. Similar assessment and judgment should be used with respect to protective relay system existing at the time of revisions to this guide. Special local conditions or considerations may necessitate the use of more stringent design criteria and practices.

CREZ Protection & Control

See section 7.2.6 for CREZ application considerations.

A yearly review should be completed to insure compliance with all NERC Reliability Standards.

7.2.2 Design and Operating Requirements for ERCOT System Facilities

1. Protective relay system shall be designed to provide reliability, a combination of dependability and security, so that protective relay system will perform correctly to remove faulted equipment from the ERCOT System.
2. For planned ERCOT System conditions, protective relay system shall be designed not to trip for stable swings which do not exceed the steady-state stability limit. Note that when out-of-step blocking is used in one location, a method of out-of-step tripping should also be considered. Protective relay system shall not interfere with the operation of the ERCOT System under the procedures identified in the other Operating Guides.

3. Any loading limits imposed by the protective relay system shall be documented and followed as an ERCOT System operating constraint. Protective relay loadability must follow the NERC requirements in PRC-023.

4. The thermal capability of all protection system components shall be adequate to withstand the maximum short time and continuous loading conditions to which the associated protected elements may be subjected, even under first-contingency conditions.

5. Applicable IEEE/ANSI guides shall be considered when applying the protective relay system on the ERCOT System.

6. The planning and design of generation, transmission and substation configurations shall take into account the protective relay system requirements of dependability, security and simplicity. If configurations are proposed that require protective relay systems that do not conform to this guide or to accepted IEEE/ANSI practice, then the Facility owners affected shall negotiate a solution.

7. All Facility owners shall give sufficient advance notice to ERCOT of any changes to their Facilities that could require changes in the protective relay system of neighboring Facility owners.

8. Facility owner's operations personnel shall be familiar with the purposes and limitations of the protective relay system.

9. The design, coordination, and maintainability of all existing protective relay systems shall be reviewed periodically by the Facility owner to ensure that the protective relay systems continue to meet ERCOT System requirements. This review shall include the need for redundancy. Where redundant protective relay systems are required, separate AC current inputs and separately fused DC control voltages shall be provided with the upgraded protective relay system. Documentation of the review shall be maintained and supplied by the Facility owner to ERCOT or NERC on their request within 30 days. This documentation shall be reviewed by ERCOT for verification of implementation.

10. Upon ERCOT's request, within 30 days, PGCs shall provide ERCOT with the operating characteristics of any generator's equipment protective relay system or controls that may respond to temporary excursions in voltage, frequency, or loading with actions that could lead to tripping of the generator.

11. Upon ERCOT's request, within 30 days, Generation Entities shall provide ERCOT with information that describes how generator controls coordinate with the generator's short-term capabilities and the protective relay system.

12. Over-excitation limiters, when used, shall be coordinated with the thermal capability of the generator field winding. After allowing temporary field current overload, the limiter shall operate through the automatic AC voltage regulator to reduce field current to the continuous rating. Return to normal AC voltage regulation after current reduction shall be automatic. The over-excitation limiter shall be coordinated with the over-excitation protection so that over-excitation protection only operates for failure of the voltage regulator/limiter. Documentation of coordination shall be supplied, by Generation Entities, to ERCOT upon their request within 30 days.

13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than

the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include under-frequency or under-voltage Load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements:

- The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties.
- The SPS shall be automatically armed when appropriate.
- The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner.
- The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS..
- When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS.

14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems.

- ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website.
- For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The

implementation schedule must be confirmed through submission of a Service Request to ERCOT.

- For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review.
- The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service.
- An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria, guides, and Reliability Standards. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days.
- As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work with the owner(s) of facilities controlled by the SPS as necessary to address all issues.
- ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate.
- ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS.

15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented.

16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS.

7.2.3 Performance Analysis Requirements for ERCOT System Facilities

1. All ERCOT System disturbances (unwanted trips, faults, and protective relay system operations) shall be analyzed by the affected Facility Owner promptly and any deficiencies investigated and corrected.

2. All protective relay system misoperation in systems 100 kV and above shall be documented, including corrective actions and the documentation supplied by the affected Facility Owner to ERCOT or NERC upon their request within five business days. All protective relay system misoperation shall be documented using Section 6.1.2, Relay Misoperation Report. Any of the following events constitute a reportable protective relay system misoperation:

   - Failure to Trip – Any failure of a protective relay system to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device.
   - Slow Trip – A correct operation of a protective relay system for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intends.
   - Unnecessary Trip During a Fault – Any relay initiated operation of a circuit breaker during a fault when the fault is outside the intended zone of protection.
   - Unnecessary Trip Other Than Fault – The unintentional operation of a protective relay system, which causes a circuit breaker to trip when no system fault is present. May be due to vibration, improper settings; load swing, defective relays, or SCADA system malfunction.
   - Employee action that directly initiates a trip is not included in this category. It is the intent of this reporting process to identify misoperations of the relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the relay system. With this in mind, if an individual directly initiates an operation, it is not counted as a misoperation (i.e., unintentional operation during tests). On the other hand, if a technician leaves trip test switches or cut-off switches in an inappropriate position and a system fault or condition causes a misoperation, this would be counted as a relay system misoperation
   - Failure to Reclose – Any failure of a protective relay system to automatically reclose following a fault if that is the design intent.

3. All SPS misoperation shall be documented, including corrective actions and the documentation supplied to ERCOT and NERC upon request within five business days. All SPS misoperation shall be documented using Section 6.1.2, Relay Misoperation Report. Any of the following events constitute a reportable SPS misoperation:

   - Failure to Operate – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occur.
   - Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed.
   - Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s).
   - Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s).

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- Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

4. Facility Owners shall document the performance of their protective relay system utilizing the method described in the paper "Transmission Protective Relay System Performance Measuring Methodology", IEEE/PSRC Working Group 13 September 16, 1999. Facility Owners shall report the performance of their 138 kV and 345 kV protective relay system for the previous twelve months to ERCOT on an annual basis. The reporting period shall be from May 1 of the previous year through April 30 of the present year. The performance data reported shall include the total number of protective relay system misoperation, the total number of events, and the factor "k".

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5. At least annually, ERCOT shall review the protective relay system misoperation reports and 345 kV performance data of Facility Owners for analysis of protective relay system performance and compliance.

6. All Facility owners shall install, maintain, and operate disturbance monitoring equipment in accordance with the requirements in Section 7.1.2.3, Data Recording Requirements.

7. Facility owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of the NERC Planning Standard I.A. These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection systems are sufficient to meet the system performance levels as defined in NERC Planning Standard I.A. and the associated Table I. All non-compliance findings shall be documented, including a plan for achieving compliance. These assessments shall be provided to NERC or ERCOT on their request within 30 days.

7.2.4 Maintenance and Testing Requirements for ERCOT System Facilities

1. The Facility Owner shall test and verify the operation of each new or modified protective relay system prior to placing the equipment in its zone of protection in service. End-to-End testing shall be done for all CREZ line installations prior to energizing.

2. Facility Owners shall have documented protective relay system maintenance and testing programs in place. Documentation shall include identification of protective relay system, a summary of testing procedures including requirements for frequency of tests, and the date last tested.

3. The Facility Owner shall periodically test and inspect all components of the protective relay system to assure continued reliability. Identified deficiencies shall be corrected. Documentation demonstrating compliance with the Facility Owner's maintenance and testing programs shall be supplied to ERCOT or NERC upon their request within 30 days.

7.2.5 Requirements and Recommendations for ERCOT System Facilities

7.2.5.1 General Protection Criteria

Dependability

1. Except as noted in Sections 4 and 5 below, all elements of the ERCOT System operated at 100 kV and above (i.e., lines, buses, transformers, generators, breakers, capacitor banks, etc.) shall be protected by two protective relay systems. Each protective relay system shall be independently capable of detecting and isolating all faults thereon.
2. The protective relay system design should avoid the use of components common to the two protective relay systems. Areas of common exposure should be kept to a minimum to reduce the possibility of both protective relay systems being disabled by a single contingency.
3. The use of two identical protective relay systems is not generally recommended, due to the risk of simultaneous failure of both protective relay systems because of design deficiencies or equipment problems.
4. Breaker failure protection should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This protection need not be duplicated.
5. On installations where freestanding or column-type current transformers are provided on one side of the breaker only, the protective relay system should be provided to detect a fault on the primaries of such current transformers. This protection need not be duplicated. Application of freestanding CTs requires extra care to ensure that the relaying is proper and that the schemes overlap.

Security

The protective relay system should be designed to isolate only the faulted element, except in those circumstances where additional elements should be tripped intentionally to preserve system integrity. For faults external to the protected zone, each protective relay system should be designed to either not operate, or to operate selectively with other systems, including breaker failure. (In this context, the limits of the protected zone are defined by the circuit breakers.)

Dependability and Security – Reliability

1. The protective relay system should be no more complex than required for any given application.
2. To the maximum degree practicable, the components used in the protective relay system should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions, to ensure that the reliability of the protective relay system is not degraded by the components.
3. The protective relay system shall be designed to minimize the possibility of component failure or malfunction due to electrical transients and electromagnetic interference or external effects such as vibration, shock and temperature.
4. Critical features associated with protective relay system and circuit breaker operation shall be annunciated or monitored.

5. The protective relay system circuitry and physical arrangements shall be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.
6. Computerized fault studies shall be used during the planning or design stages to analyze the effects of an addition or modification to the ERCOT system and to determine proper protective relay system coordination.
7. CREZ facilities shall be designed utilizing the best technologies available to balance dependability and security for maximum protection reliability.

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Operating Time

The objective of the protective relay system is to take corrective action in the shortest practical time with due regard to selectivity, dependability and security. In cases where clearing times are deliberately extended, consideration should be given to the following:

1. Effect on ERCOT System stability or reduction of stability margins.
2. Possibility of causing or increasing damage to equipment and subsequent extended repair and/or outage time.
3. Effect of disturbances on service to customers and neighboring Facility Owners.

Testing and Maintenance

1. The design of the protective relay system both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance. Test devices or switches should be provided to eliminate the necessity for removing or disconnecting wires during periodic testing. All CREZ facilities protection systems shall be designed to support periodic testing and maintenance while the facility remains in-service.
2. Commissioning of new equipment should consist of the following steps:
   - Relay installation wiring diagrams cross-checked against schematics
     - After completion of construction, physical check of wiring and relay installation
     - Check and testing before energizing of all equipment in the zone of protection, including relay testing. It is desirable to test the relays at the setting the relay will have in service
     - Check of supporting paperwork, such as relay test reports
     - Check that the relay settings when received from the manufacturer concur with the intended manufacturer's specifications
     - Calibrate and check that proper utility's settings have been made
     - Maintain a record of trip check and energizing procedure performance
     - Maintain a record of in-service measurement of voltage, current magnitudes, phase angles, and a comparison to expected values and to other instrumentation
     - Release to Facility Owner for service
   - All CREZ lines shall have End-to-End testing performed prior to energizing.

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Analysis of System Performance and Associated Protection Systems

1. Relay operation and settings shall be reviewed periodically and whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

2. Naturally occurring faults and other system disturbances should be analyzed as a source of information as to the health of relay schemes in the System. Sources of information usually available are:

   - Short circuit study for the exact conditions of the fault
   - Fault recorder traces
   - Sequence of events data recording the opening and closing of contacts in the protective relay scheme and associated communication equipment
   - Fault locator data
   - SCADA (Supervisory Control And Data Acquisition) logger output of breaker operation and alarms
   - Interviews with operating personnel and/or other witnesses
   - Field report of relay flags and breaker counter changes
   - Field report of the fault location, if found
   - Records of relay setting, relay testing, trip check and energize procedures as carried out, in-service measurements, relay wiring diagrams and schematics, manufacturers' information
   - Other coworkers and System Protection Working Group members
   - Manufacturers' application and design engineers

3. Steps one can follow in analyzing a disturbance are:

   - Gather data
   - Create a time line consisting of events and periods between events
   - Compare actual and calculated values of current and voltage during the periods between events
   - Compare actual and expected breaker operations and flags
   - Choose the least complicated explanation for contradictory information and to fill in missing information
   - Gather additional information as indicated to prove or disprove explanations
   - Iterate
   - Document by issuing a report of all findings, changes, and recommendations
   - After a reasonable time, check back to see if the recommendations have been carried out
   - Use modern playback devices capable of re-simulating the events from the captured fault event data.

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7.2.5.2 Equipment and Design Considerations

Current Transformers

1. Current transformers (CTs) associated with the protective relay system shall have adequate steady state and transient characteristics for their intended function.

2. The output of each current transformer shall remain within acceptable limits for the connected burdens under all anticipated fault currents to ensure correct operation of the protective relay system.
3. Current transformers or their secondary windings shall be located so that adjacent protection zones overlap.
4. Current transformer secondary wiring shall be grounded at only one point. When multiple current transformers are interconnected, the combination shall have only one ground.
5. Other considerations:
    - Internal bushing CTs are preferred over external slip-over CTs
    - 10L800 (C800) class CTs are preferred for relaying
    - Breakers and free-standing CTs with four or more sets of CTs are preferred
    - Over-the-bushing external CTs can sometimes solve problems when there aren't enough CTs. Note that there may be an unprotected region between the external CT and the bushing CT.
    - Shorting type terminal blocks should be provided for all CTs
6. A separate current transformer shall be provided for each protective scheme for all CREZ projects.

Voltage Transformers and Potential Devices

1. Voltage transformers (VTs) and potential devices associated with the protective relay system shall have adequate steady state and transient characteristics for their intended functions.
2. Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their relay accuracy over their specified primary voltage range.
3. Usually one set of VTs (with two separate secondary windings per VT) per bus (i.e. single bus substation configuration) or per power system element (i.e. ring bus and breaker-and-a-half substation configurations) is sufficient. The two protective relay systems protecting ERCOT System facilities may use separate secondary windings of the VTs or one of the secondary windings may be dedicated to supplying the polarizing potential and the other winding used to supply other protection and monitoring functions.
4. Voltage transformer and potential device secondary wiring shall be grounded at only one point. (ANSI/IEEE C57 recommends grounding at the panel.)
5. Voltage transformer installations shall be designed with due regard to ferroresonance due to capacitance across the interrupter at 138kV and above.
6. Other considerations
    - Special attention should be given to the physical properties of secondary circuit fuses
    - Capacitor coupled voltage transformers are suitable for relaying and SCADA telemetry

- Report loss of VT voltage (VT fuse failure) over SCADA

7. For all CREZ projects, one primary VT with two or more secondary windings shall be provided so that each protection system has an independent secondary voltage input supplied from separate secondary windings and, if necessary, a separate winding shall be available for voltage polarizing.

Batteries and Direct Current (DC) Supply

1. DC batteries associated with the protective relay system shall have a high degree of reliability.
2. Two batteries each with its own charger should be provided at each location. An acceptable alternative is one battery with two separately protected branches. The systems protecting a zone shall be supplied from the separate sources or branches. For a new facility, two batteries shall be required in locations that remote backup clearing of lines and substation faults is not achieved. Where only one battery is used, remote backup clearing of line and substation faults is required.
3. Each battery shall have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the AC supply source, for the period of time necessary to transfer the load to the other battery or to re-establish the supply source. Each battery and its associated charger shall have sufficient capacity to supply its share of the DC load of the station.
4. A fault at the battery terminals can only be interrupted by a mid-bank protective device. If a mid-bank protective device is not used, then the connections between the battery terminals and the main protective devices shall possess the highest possible degree of reliability.
5. The battery chargers and all associated circuits shall be protected against short circuits. All protective devices shall be coordinated to minimize the number of DC circuits interrupted.
6. The regulation of DC voltage shall be designed such that, under all possible loading conditions, voltage within acceptable limits will be supplied to all devices.
7. DC systems shall be monitored to detect abnormal voltage levels, both high and low, DC grounds, and loss of AC to the battery chargers. Loss of DC to relay schemes shall be alarmed. Also, where possible the loss of AC to the battery chargers and loss of DC should be provided as SCADA alarm inputs.
8. DC systems shall be designed to minimize AC ripple and voltage transients.
9. The DC circuit protective devices used shall have published DC interrupting ratings suitable for the required circuit duty.
10. For all new CREZ stations two batteries each with its own charger shall be provided at each location. It is highly recommended to have one spare charger on site. Items 3 – 9 shall be followed for each independent battery source.

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AC Auxiliary Power

1. There should be two sources of station service AC supply, each capable of carrying all the critical loads associated with the protective relay system.
2. Failure of station service AC supply should be alarmed over SCADA.

Circuit Breakers

1. Two trip coils, one associated with each protection system, shall be provided for each operating mechanism. The failure of one coil shall not damage or impair the operation of the other coil.
2. The design shall be such that the breaker will operate if either both trip coils are energized simultaneously, or either trip coil alone, and verified by tests.
3. Circuit breaker auxiliary switches used in protection systems should be highly reliable with a positive make-break action and good contact wipe. Multiplier contacts simulating breaker auxiliary switches should be used with caution in protection systems.
4. A three-phase and line-to-ground interrupting study to validate or indicate breaker interrupting rating shall be performed.
5. For all CREZ facilities it is highly recommended to have a cross tripping means so that each protection scheme can reach both trip coils without compromising the separation of the DC supplies.

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Communications Channels

1. Where communication channels are required for the protective relay system purposes, the communication facilities shall have a degree of reliability no less than that of the other protective relay system components. For extra security, the output contacts from two independent channels may be wired in series.
2. Where communication channels are required in each of the two protective relay systems, the channels shall be separated physically and designed to minimize the risk of both channels being disabled simultaneously by a single contingency.
3. Communication channels shall be provided with means to verify signal performance.
4. Other considerations
   - Report loss of channel over SCADA
   - Automatic testing of power line carrier (PLC) is desirable to reduce false trips from failure to block
   - Split up PLC loads between DC sources so that loss of one fuse does not disable all the carrier sets. If all the carrier sets were to be disabled, then multiple false trips during a fault could result.

5 For all new CREZ lines a fiber communications cable shall be provided. With all CREZ new or rebuilt lines having a fiber cable a self-healing SONET Ring with route diversity is available for protection, control, metering, and SCADA, etc. With the available fiber a short path (direct station t-to-station) is utilized by relay system #1 and the long path utilizing the SONET Ring supports communications for relay system # 2.

Control Cables and Wiring

1. Control cables, wiring and auxiliary control devices should be such as to assure high reliability with due consideration to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.
2. Other considerations

- Shielded cable may be necessary for certain relay and SCADA applications
- AC or DC go-and-return functions should be implemented in the same cable to avoid induction loops
- Individual wires in cables should have colored jackets, not black jackets with a "color" printed on the jacket
- Standardization of the relationship between wire colors and functions is desirable
- No splice in any wire or cable
- All cables terminated on terminal blocks
- For all CREZ facilities shielded cable is highly recommended.

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Environment

1. Means shall be employed to maintain environmental conditions that are favorable to the correct performance of the protective relay system. Particular attention should be given to solid-state equipment installations.
2. Other environmental hazards to look out for:

➢ Fire ants	➢ Rats
➢ Snakes	➢ Dust, dirt, grime
➢ Trash and leftover hardware	➢ Water
➢ Gunfire	➢ Theft of substation and transmission grounds
➢ Hand-held radio keyed near solid-state relays	➢ Batteries located in same room as relays (battery fires)
➢ Severe cold weather conditions can impact operation of circuit breakers, DC battery, and carrier signals.	

7.2.5.3 Specific Application Considerations

Transmission Line Protection

1. Each of the two independent protective relay systems shall detect and initiate action to clear any line fault without undue system disturbance. The protective relay system shall operate for line faults so that, if ultimate clearing should be accomplished by a breaker failure scheme, a widespread disturbance will not result. A protective relay system, which can operate for faults beyond the zone it is designed to protect, shall be selective in time with other protective relay system, including breaker failure.
2. Transmission line protection should consist of:

- Primary phase and ground protection over a communications channel.
- Backup relaying with at least two zones of phase protection.
- Backup relaying with at least two zones of ground protection, or backup relaying with ground directional overcurrent relaying (time delay and instantaneous).
- "Ground chain protection" to recognize and trip for a three-phase fault right at the terminals, in service for a short period of time just as the line is energized, for lines with line side VTs.
- Recognition and trip for open conductor is desirable but not required.
- Overload protection is provided by SCADA analog alarms and dispatcher discretion.
- Fault detector relays to supervise phase distance relaying to prevent inadvertent trip due to VT failure.
- Short lines may require special attention, such as dual primary schemes, etc.
- Fuses shall not be used in the 3Vo polarizing supply for ground relays.
- The setting for synchronization check relays should be based on system studies that identify the voltage angles necessary for a successful re-close.

3. For all new CREZ Lines the protection shall consist of:

- Current Differential over a fiber communications channel utilizing short path
- Second primary system utilizing long path featuring self-healing SONET Ring being current differential or POTT.
- "Ground chain protection" or “switch –onto-fault” to recognize and trip for a three-phase fault right at the terminals, in service for a short period of time just as the line is energized, for lines with line side VTs dependent on distance measurement.
- Recognition and trip for open conductor is desirable but not required.
- “Loss –of-Potential” function shall be utilized for schemes dependent on voltage for correct operation.
- Fuses shall not be used in the 3Vo polarizing supply for ground relays.
- The setting for synchronization check relays shall be based on system studies that identify the voltage angles necessary for a successful re-close. Reclosing shall also include a slip measurement and block reclosing for a predetermined slip speed.
- Protection schemes must meet or exceed NERC loading requirements in PRC-023.

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Transmission Station Protection

1. Each zone in a station shall be protected by two independent protective relay systems. For zones not protected by line protection, at least one of the two protective relay systems shall be a differential type.
2. The protective relay system shall be designed to operate for station faults so that, if ultimate clearing is accomplished by a breaker failure scheme, a widespread disturbance will not result. The protective relay system shall be designed to operate properly for the anticipated range of currents.
3. Station protection should consist of:
   - Bus differential or bus overcurrent protection of all buses
   - All transformers protected by transformer differential, transformer overcurrent, or fuses (for small transformers). Note that ferroresonance is possible for fused transformers above 69kV.
   - Sudden pressure relay protection for transformer main tanks and transformer tap changer compartments
4. For all new or rebuilt CREZ station facilities the station protection shall consist of:
   - Two independent redundant high-speed protection schemes with independent auxiliary relays providing cross tripping while maintaining battery separation through a second auxiliary device or other means.
   - Sudden pressure and Buchholz relay protection for transformer main tanks and transformer tap changer compartments
   - Backup protection as required by power system configuration.
   - Protection schemes must meet or exceed NERC loading requirements in PRC-023.

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Breaker Failure Protection

1. Breaker failure protection should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault.
2. The breaker failure protection should be initiated by each of the protection systems that trip that breaker. It is not necessary to duplicate the breaker failure protection itself.
3. Induction cup or solid state fault current detectors shall be used to determine if a breaker has failed to interrupt.
4. Plunger or clapper type overcurrent relays are not recommended as breaker failure fault detectors.
5. Breaker failure protection shall utilize a modern high-speed dropout designed fault detector for all CREZ facility breakers while conforming to items 1 & 2 above.

Generator Protection

1. Generator faults shall be detected by more than one protective relay system. These may include faults in the generator or generator leads, unit transformer, and unit-connected station service transformer.
2. Generators shall be protected to keep damage to the equipment and subsequent outage time to a minimum. In view of the special consideration of generator unit protection, the following are some of the conditions that should be detected by the protection systems:

- Unbalanced phase currents
- Loss of excitation
- Over-excitation
- Field ground
- Inadvertent energization (reverse power)
- Uncleared system faults
- Off-frequency

It is recognized that the overall protection of a generator will also involve non-electrical considerations. These have not been included as part of this criteria.

3. The apparatus shall be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional relays, as the normal relays may not function satisfactorily at low frequencies.
4. A generator shall not be tripped for a system swing condition except when that particular generator is out of step with the remainder of the system. This does not apply to protective relay system designed to trip the generator as part of an overall plan to maintain stability of the ERCOT System.
5. The loss of excitation relay shall be set with due regard to the performance of the excitation system.
6. The protection of the generator and the transmission grid must be coordinated according to the requirements in NERC PRC-001.

Automatic Under-Frequency Load Shedding (UFLS) Protection Systems

Automatic under-frequency Load shedding systems are classified as protective relay systems. The maintenance requirements, discussed in Section 7.2.4, Maintenance and Testing Requirements for ERCOT System Facilities, apply to under-frequency Load shedding protection systems as well.

1. Automatic under-frequency Load shedding systems are generally located on equipment operated below 60 kV; however, they have a direct effect on the operation of the system during major emergencies.
2. The criteria for the operation of these protection systems are detailed in Section 2.9, Requirements for Under-Frequency Relaying.
3. Automatic under-frequency Load shedding protection systems need not be duplicated.
4. Generator and turbine under-frequency protection systems shall be coordinated with Section 2.9, Requirements for Under-Frequency Relaying.
5. On pressurized water reactor steam supply units where under-frequency related protection systems are installed to detect loss of coolant flow condition, these protection systems shall be coordinated with the automatic under-frequency Load shedding program.
6. Automatic Load restoration for a UFLS operation is not currently utilized in ERCOT.

Automatic Under-Voltage Load Shedding Protection Systems

Automatic under-voltage Load shedding systems are classified as protective relay systems. The maintenance requirements, discussed in Section 7.2.4, Maintenance and Testing Requirements for ERCOT System Facilities, apply to under-voltage Load shedding protection systems as well.

1. The requirement for under-voltage relaying shall be determined by system studies performed/administered by ERCOT designated working groups or equipment owners. The system studies should indicate the following:
   - Amount of Load to be shed to restore voltage to minimum acceptable level or higher,
   - The minimum and maximum time delay allowed before automatically shedding Load,
   - The voltage level(s) at which to initiate automatic relay operation, and
   - The location(s) for effectively applying under-voltage Load shedding protection systems.
2. Automatic under-voltage Load shedding protection systems need not be duplicated.
3. Analyses shall be performed on under-voltage Load shedding schemes by working groups and/or equipment owners as assigned by ERCOT to demonstrate that they are expected to act before generators trip Off-line due to the protective relay requirements described in Section 3.1.4.6, Protective Relaying Requirement. A specific exemption from this analysis requirement may be provided by the ERCOT Reliability and Operations Subcommittee (ROS).
4. Under-voltage protection systems shall be designed to coordinate with other protective devices and control schemes during momentary voltage dips, sustained faults, low voltages caused by stalled motors, motor starting, etc.
5. Automatic Load restoration for a UVLS operation is not currently utilized in ERCOT.
6. The scheme shall be designed to ensure reliable operation and to prevent false tripping.

7.2.6 CREZ Application Considerations

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- **Issues with carrier-based schemes for EHV line protection**

The carrier-based schemes such as directional comparison blocking scheme (DCB) or permissive overreaching transfer trip scheme (POTT) are relying on the phase distance (21P) / ground distance (21G) / overcurrent (50N) / directional (67N) elements of digital relays to detect / distinguish internal and external faults so as to initiate high-speed trip for internal faults. The carrier-based schemes are susceptible to misoperation because of some issues related to their building blocks.

1. Mutual Coupling

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For long distance double-circuit lines or parallel lines in the same right-of-way, the mutual coupling between the two lines can be a problem for carrier-based schemes. When ground fault occurs, the 21G or 50N elements may overreach or underreach under various operational conditions because of the zero sequence voltage induced from zero sequence current flowing on the other line. Similarly, the 67N element can assert the wrong direction due to the influence of these zero sequence currents.

2. Current reversal

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The parallel lines cause a current reversal problem in DCB or POTT. In these schemes, the 21P/21G/67N elements for the healthy line will see fault direction change when the breakers of the faulty line are not tripped simultaneously. Hence the healthy line may be tripped by a DCB or POTT scheme.

3. Power Swing

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When there is a loss of critical generation or transmission lines, power swing can occur in the area due to the unbalance between the generation and the load. It is imperative that the other lines in the area should remain intact to keep from aggravating the situation if the power swing is recoverable. The 21P elements are very susceptible to power swings because of the apparent impedance variations caused by power swing. Since DCB or POTT use 21P elements for phase fault detection, these schemes are susceptible to power swing mis-operations.

4. Voltage transients

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The voltage transients that are caused by external faults, CCVTs, motor loads, etc. may have significant impact on the performance of distance elements or directional elements so as to cause mis-operation in DCB or POTT.

5. Carrier

The failure of the carrier equipment or channel can cause either a security or dependability failure. The security failure results in a failure to trip and the dependability failure results in an over trip.

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• Issues with series-compensated EHV line protection

A series-compensated EHV line can improve power transmission capability and system stability, meanwhile it can introduce a number of issues to distance/directional overcurrent elements as well as carrier-based schemes.

1. Non-linear apparent impedance from series capacitor and Metal Oxide Varistor (MOV)

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To prevent damage from over-voltage during the faults, the series capacitors could be protected by air gap, MOV or thyristor controller (TCSC), among which MOV is mostly used. A MOV is installed in parallel with the series capacitor bank. If the fault current is high, the MOV will conduct so that the capacitor bank could be bypassed. But if the fault current is not high enough, the MOV may not fully conduct such that the series capacitors and MOV are both accounted in the apparent impedance, which is non-linear that caused the three sequence (positive, negative, zero) component networks to be

mutually coupled with each other. The distance relays and ground directional overcurrent relays are relying on the sequence components therefore they could be confused.

2. Voltage and current inversion

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In DCB or POTT, the distance elements and directional overcurrent elements are used to determine fault direction, which is derived from the phasor relationships among voltages and currents in phase quantities or sequence components. The natural phasor relationship of those voltage and current signals could be shifted significantly by the series capacitor and MOV, which is well known as voltage inversion and current inversion. Because of this, neither DCB nor POTT can be guaranteed to trip for internal faults only.

3. Sub-synchronous resonance

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When fault occurs in the vicinity of a series-compensated line, sub-synchronous resonance could be produced from series capacitance and the network inductance. The corresponding low frequency signals as seen by relays can hardly be filtered out because the digital filters are designed with small data windows for fast response. Hence the estimated phasors could have error in both magnitude and phase. Since the phasor estimation is fundamental to a digital relay, all the protection functions could be affected.

4. Distance relay settings

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The settings for series compensated line are difficult for distance protection coordination. Because of compensation, the distance zone 1 reach has to be reduced to a small fraction of the line, or even disabled. The time delayed distance zone 2 needs to reach far enough to cover the line with margins when series capacitors are bypassed. But this could cause overreaching problem when the capacitors are not bypassed. For ground distance relays, the zero-sequence compensation factors are fixed settings. But for a series-compensated line, the compensation factor can be drastically affected by the fault position and fault current level. It means the reach of ground distance element could have significant error.

5. The others

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The above are just some known issues for series compensated line protection. There are still some unknowns that are up to specific system configurations and system components. The fault transients caused by interactions among generators, transformers, power electronics, reactors, motors, CVTs and series capacitors are difficult to determine without extensive simulation studies. The performance of protective system may only be evaluated by a close-loop type real time digital simulation system such as RTDS.

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• Recommendations on CREZ line protection schemes

Most CREZ 345kV lines will be built as double circuits that have significant mutual coupling between the parallel lines. Some CREZ 345kV lines are long lings with series compensation. Since these 345kV lines will compose the bulk transmission system for the competitive renewable energy zone (CREZ) in Texas, it is important to deploy the most reliable line protection schemes for them.

1. Use fiber-based line differential scheme as primary protection

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Compared with carrier-based pilot schemes such as DCB or POTT, the current differential (87L) scheme can avoid all the problems mentioned above. The 87L relays uses optical fibers as communication channels to compare current flowing into the line at one terminal and out of the line at the other terminal, such that the differential current caused by internal and external faults would be significantly different. Since the 87L functions on current input only, it is not affected by the voltage-current phase relationship or any voltage transients. Compared with carrier based DCB or POTT, it is immune to the problems caused by mutual-coupling and series compensation. In addition, it is stable during power swing and there is no coordination issue with the 87L function.

Because of optical fiber communication, the 87L was regarded as expensive in the past. However, ever since the advent of technology such as Optical Fiber Composite Overhead Ground Wire (OPGW), the cost of fiber communication for a new transmission line has become fractional, compared with the benefit it brings. The vital importance of CREZ line protection can justify the additional cost to use OPGW for a new transmission line. In addition, the fiber cables will become part of the communication infrastructure to handle the increasing demands of SCADA data, Synchrophasor data, disturbance monitoring system data, substation surveillance system, voice communication, etc. Considering these benefits and the fractional cost of OPGW cable, there is no doubt that any utilities involved with CREZ shall install OPGW for every new transmission line. CREZ represents the building or re-building of the ERCOT transmission backbone. The CREZ facilities will last 75 years or more. This is the time to maximize the new power grid protection & control performance.

2. Redundancy

The protection redundancy is an important link of the overall system reliability. Since the CREZ 345kV lines compose the backbone transmission system of renewable energy in large capacity, it is recommended to have dual high-speed primary schemes for all CREZ 345kV lines. The primary scheme shall be fiber-based 87L, while the other high-speed scheme could be 87L,or POTT over a diverse route. Dual 87L is recommended for short line applications, series-compensated applications and long distance double-circuit applications. By using one OPGW cable per line a network capable of both a short path and a long path architecture can be developed resulting in independent dual routes for each relay system.

If both primary and secondary schemes are fiber-based 87L, different types of relays shall be used to prevent common-mode failure.

The outcome of a fiber based communication network having both short path and long path through a self-healing SONET Ring is that dual independent high-speed protection is available to clear line faults rapidly and reliably within the renewable energy undervoltage ride through capability.

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7.3 Document Control

Change History

ISSUE/DATE	REASON FOR ISSUE
Version 0.1	Draft for Review

ISSUE/DATE	REASON FOR ISSUE
December 7, 2000	
Version 0.2 December 29, 2000	Insert comments
Version 0.3 January 19, 2001	Insert comments from seminar
Version 0.4 February 5, 2001	Comments from second Working Group
Version 1.0 February 28, 2001	Updated from Working Group comments. Submitted to Technical Advisory Committee to approve handover to the Reliability Operating Subcommittee
May 1, 2002	OGRR103
July 1, 2002	OGRR104
September 1, 2002	OGRR107 & OGRR109
December 1, 2002	Reformatted numbering from Appendix B to Section 7.
January 1, 2003	OGRR121 revised Section 7.2.2.5 for fault recording equipment.
March 1, 2003	Formatted header and page numbering.
May 1, 2003	Moved “Planning” text to Section 5 and updated section numbering.
February 1, 2004	OGRR140 updated Section 7.2.2
May 1, 2004	OGRR144 updated Section 7.2.5.3
May 1, 2005	OGRR162
April 1, 2006	OGRR172
August 1, 2006	OGRR179
July 1, 2007	Admin OGRR201