Power Plant and Transmission System Protection Coordination

A report to the Rotating Machinery Protection Subcommittee
of the Power System Relay Committee
of the IEEE Power Engineering Society

Prepared by Working Group J3

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Abstract

In response to the North American electrical system disturbance that occurred on August 14, 2003, the North American Electric Reliability Corporation (NERC) produced a Technical Reference Document (TRD) entitled "Power Plant and Transmission System Protection Coordination". This document "…explored generating plant protection schemes and their settings…to minimize unnecessary trips of generation during system disturbances."

This report provides recommendations to the J Subcommittee on coordination issues and other relevant matters gleaned from the NERC Technical Reference Document and the review of the relevant IEEE Guides to be used as feeder material and technical additions for consideration in the next revisions of IEEE C37.91, C37.96, C37.101, C37.102, and C37.106. It also provides comments to NERC for possible revisions to the Technical Reference Document.

Introduction

The Working Group reviewed each of the protection functions discussed in the NERC Technical Reference Document (TRD) and provided comments. The Working Group discussed the comments and divided them into separate documents as applicable to the respective Guide or the NERC TRD. The following tables identify the relevant issues between the NERC TRD and the IEEE Guides, with proposed additions and/or changes, which may be considered for future revisions to the NERC TRD and the IEEE Guides.

Contents

Comments to be addressed by: IEEE C37.91

	Location in NERC TRD (Page Number and Subsection)	**Relevant Issues**	**Proposed Addition to specific IEEE Guides**
1.	Pages 154-157 3.15	No discrepancies or need for clarification found within TRD.	Propose more description on use of 87U. Suggest Expand in C37.91-2008. Use diagrams from NERC TRD Section 3.15.1.3 after a technical review.

Comments to be addressed by: IEEE C37.96

	Location in NERC TRD (Page Number and Subsection)	**Relevant Issues**	**Proposed Addition to specific IEEE Guides**
1.	Page.48, 3.3.1	Motor under voltage protection coordination issues with transmission system are well covered in IEEE C37.96 (Guide for AC Motor Protection) as per Items 5.7.2.1& Item 7.2.4,	For clause 7.2.4 add wording to convey the intentions of the following NERC recommendations: "In some applications the motor rated terminal voltage is less than system nominal to allow for inherent system voltage drops (e.g., 4,000 volts on a 4,160 volt bus)." This needs to be taken into consideration when evaluating the motor capability based on reduced voltages". Also some motors have rated torque capability at a reduced voltage to provide margin.
2.	--		Auxiliary systems at power plants contain a large number of motors, which are constant KVA devices that can be overloaded due to low voltage. The lower their operating voltage, the more current the motor draws. Thus, plant auxiliary system motors can and have tripped via their thermal protection for low generator terminal voltage. For essential-service motors undervoltage relays should not be used to protect these motors. The thermal protection on the motors should be the protection element that protects these motors from overload.(If the undervoltage condition is severe, the motor should be quickly disconnected).
3.	--	Item 5.7.2.1 Undervoltage protection: Power plant station service is an area where this condition may exist. During a system disturbance that reduces voltage, the system may separate and completely collapse upon additional loss of generation capacity, which can occur if the motors drop out on undervoltage. The successful recovery of the system depends on maintaining each unit at maximum possible capability. In this case, the fans, pumps, etc. that serve the unit must remain in operation, even though the voltage is reduced below a normally designated safe value. Recovery can then be	Design considerations for power station voltage regulation on auxiliary system buses due to transmission system voltage variation are well covered in IEEE 666 clause 9.

		accomplished by suitable operator action. When a motor is not considered essential, the undervoltage device may be connected to trip the appropriate contactor or circuit breaker where tripping is allowed. A time delay should be included to allow faults or system disturbances to clear before tripping the breaker. The time delay depends on, and should be coordinated with, the time to clear or isolate system faults by backup relay operations.	

Comments to be addressed by: IEEE C37.101

	Location in NERC TRD (Page Number and Subsection)	**Relevant Issues**	**Proposed Addition to specific IEEE Guides**
1.	--	There is no difference between Generator connections (A) and (F) in Table 1 unless somebody reads the last paragraph on Page 7 of C37.101-2006.	Generator connection diagrams should be revised to show any generator side breakers.

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Review of NERC Technical Reference Document - Power Plant and Transmission System Protection Coordination

Comments to be addressed by: IEEE C37.102

	Location in NERC TRD (Page Number and Subsection)	**Relevant Issues**	**Proposed Addition to specific IEEE Guides**
	21-Phase Distance Protection		
1.	Page. 22, 3.1.1. Purpose of Generator Function 21 — Phase Distance Protection and 3.1.2 Page. 24, 3.1.2.2 Coordination of Generator and Transmission Systems	loadability under a stressed system condition is address on this page	C37.102 do not have specific section addressing this, only a general statement "…Stability studies may be needed to help determine a set point to optimize protection and coordination."
2.	Page. 22, 23, Sec 3.1.2	Two methods of testing loadability under a stressed system condition are presented. One is a conservative method with two test points. The other is based on worst case dynamic modeling when the first method restricts the desired setting.	This conservative method for loadability test under a stressed system condition should be presented in the Annex section of C37.102. The calculation is fairly straight forward. The C37.102 WG should look into the premise for the proposed setting before adopting the two recommended loadability setpoint tests recommended by NERC.
3.	Page. 26, Sec 3.1.3	"…methods such as out-of-step blocking should be incorporated into impedance function tripping logic to assure the function will not operate for stable swings."	Poor wording here? Out-of-step implies unstable swing. Should it say blinders rather than out-of-step blocking? As far as I know, out-of-step blocking is typically not part of generator protective function. C37.102 WG to discuss out-of-step blocking. Also refer to the section on out of step tripping to tie the two together.
4.	Page. 28-37, Sec 3.1.5 Setting Example	Setting example	Consider incorporate this loadability consideration into annex of C37.102.
	24-Volts per Hertz		
1.	Page. 40 3.2. Overexcitation or V/Hz Protection (Function 24)	Section 3.2 includes much discussion on the coordination aspects of Device 24 – Overexcitation Protection, or Volts per Hertz. Typically, generators will be damaged if V/Hz exceeds 105% of the generator's rated voltage divided by its rated	Thus, it is important that V/Hz protection must coordinate with UFLS programs. But this coordination is not relay-to-relay in the traditional sense of overcurrent or impedance relays, but among generator and transformer characteristics, generator excitation controls, generator and transformer overexcitation protection, and the UFLS programs. Coordination is also required on a human

		frequency. Also, any GSU or unit auxiliary transformer connected to the generator terminals will be damaged if V/Hz exceeds 105% of the transformer's rated voltage divided by its rated frequency at full load and 0.8 pf, or 110% if unloaded. Device 24 protection is applied to protect these elements from excessive V/Hz. The reason this may be a concern for power plant/transmission system coordination is that the generator/GSU unit may be tripped unexpectedly if system voltage and frequency is not maintained within these limits during system disturbances which result in underfrequency or overvoltage. And if an underfrequency (UF) event is already occurring, generator trips will only make it worse, possibly leading to total system collapse. All NERC regions have underfrequency load shedding (UFLS) programs designed to arrest system collapse due to a deficiency of generation to load. The UFLS programs automatically shed load in an attempt to achieve a balance between generation and load, and thus preserve the majority of the system. UFLS schemes assume generators stay connected to supply the remaining load. Most regional reliability standards include some provision that if a generator must trip before the UFLS program plays out, additional load must be shed equivalent to the lost generation.	and organizational level, among the many players in UF events – planning coordinators, generator owners and operators, transmission owners and operators, distribution providers, etc. All must work together to make the program successful. Thus, there are many unknowns to consider. The J3 Report should consider in red including the following: 1. A discussion of the dynamic and largely subjective nature of UF events. The UFLS programs are based on simulation studies, which make many assumptions that are not all based on direct empirical data. The programs shed multiple blocks of load at different stages of declining frequency. As each block of load is shed, it may not be sufficient to arrest the frequency decline, and the system may continue to the next stage of the UFLS program. Or it may be more than sufficient leading to a frequency overshoot, causing mechanical overspeed tripping of generators, making them unavailable for restoring the system. A third possibility is that the frequency may stabilize at a reduced level for an extended period, which could result in machines accumulating some hidden damage, even though the V/Hz protection doesn't operate. 2. A discussion of the data that needs to be exchanged between the entities involved. 3. A discussion of the importance of controlling reactive elements such as capacitor banks and reactors to prevent overvoltage or undervoltage during a UF event. 4. The importance of time delays in the various active elements. Protective devices must be set with adequate margin to ensure equipment protection, while providing as much time as possible for the UFLS program to operate. 5. The importance of stability studies to validate coordination. If tripping of some generators cannot be avoided, the UFLS program may need to be revised to accommodate the loss. 6. Islands – system separation is the most probable cause of frequency and voltage excursions within a large interconnection. 7. Coordination procedure – recommendations and examples for achieving coordination.
	27-Undervoltage		

1.		General comments	An indirect effect of low system voltage that has tripped generators during system disturbances is the loss of auxiliary motors, which overheat due to extended operation at low voltages. Local motor protection trips these motors. With the loss of key auxiliary motors, steam and gas turbines typical trip— resulting in the loss of these generators. There is more to the ability of a power plant to withstand close-in electrical faults than just maintaining generator transient stability with the high-voltage network. The generating unit or units must remain in operation. That means that the medium- and low-voltage distribution systems within the power plant must sustain the turbine generator auxiliary systems despite the severe voltage dips that will result from the nearby network fault. In a thermal power plant, the critical systems to be considered may include: • boiler feedwater • circulating cooling water • condensate • auxiliary cooling water • turbine generator lube oil • generator seal oil (H2 cooled units) • fuel gas compressors (if required) • Liquid fuel forwarding equipment (if required). Generally speaking, the time constants associated with steam cycle systems (feedwater, cooling water, condensate, and so on) are long enough that brief service interruptions will not result in a shutdown of the power plant. Nevertheless, the electrical protection systems must be designed and coordinated to accommodate the resulting voltage disturbances without nuisance trips and allow the successful reacceleration of auxiliary motors that have either tripped or slowed down considerably. This will typically result in protection settings outside the range of those usually found in plants not subject to a voltage ride through (VRT) requirement. Of greater concern are the auxiliary systems directly associated with the turbine generator equipment. Lube and seal oil systems are critical to plant safety and operation and may have a low tolerance for voltage dips or interruptions unless special features are designed into the mechanical and fluid systems. In gas

			turbine–based plant configurations (simple or combined cycle), gas and liquid fuel delivery systems are also of high importance with respect to sustained operation and must be considered. Undervoltage release which provides only temporary shutdown on voltage failure and which permits automatic restart when voltage is re-established, should not be used with such equipment as machine tools, etc., where such automatic restart might be hazardous to personnel or detrimental to process or equipment. The minimum motor terminal voltage during starting is limited only by the accelerating torque requirements and the thermal capability of the rotor. Voltage dips to 75% or less may be permissible if these criteria are satisfied. The mechanical load to which the motor is connected determines the shaft power a motor must deliver. When voltage at a running motor is reduced, current must increase to meet load requirements. At rated voltage, load curve intersects the motor torque-speed curve when the motor operates at rated speed and current. At 80% voltage, motor torque is reduced by the square of the voltage reduction and the motor must slow down to intercept the load torque curve. Although the current curve is reduced in proportion to the voltage reduction, the reduction in speed produces a net increase in motor current. Set points for bus and source transformer overcurrent protection must allow for starting and increased running current. Most motors have a breakdown torque in the order of two times rated torque. At 70% voltage, the breakdown torque of such a motor would be equal to rated torque ($200\%*0.7^2 = 100\%$) and the motor would just meet its output torque rating. If the start of a large motor and the increased loading from running motors pulls the bus voltage down to near this value, running motors may be unable to meet their load requirements and will stall. Undervoltage or overload protection must then operate to trip the bus and prevent damage to the connected motors and supply circuit. The variation of the medium-bus voltage is affected by the variation in the source voltage and the voltage reduction through the unit auxiliary transformer. It is not unusual to have a variation range of 15%. There is also a voltage reduction between the medium and low-voltage buses due to the impedance and load of

			the substation transformer, which may be approximately 5%. Since the low voltage will vary as the medium voltage varies, and since there is an additional reduction due to the substation transformer, the low voltage system may be the worst case condition. IEEE-666.Item 9.7.6 (Total voltage regulation consideration) Transient voltage regulation during starting of large motors in generating stations is usually well outside the voltage ranges established by ANSI C84.1. System designs that permit transient voltage dips to 75% to 80% are not uncommon and are usually quite acceptable in generating station applications. The primary consideration during these extreme motor starting dips is the dropout voltage of relays and contactors rather than the effect on auxiliary equipment. Once motors stall due to exposure to low voltages, they will try to recover speed automatically as system voltages recover. To recover speed the motor will draw heavy amounts of reactive power in the same manner as when it was first started. The combined reactive power needs of many motors trying to recover from a stalled condition could prevent system voltage recovery. Eventually an entire power system could collapse
2.		General comments for C37.102 Page 71, 4.5.7.1	Where undervoltage protection is required such as for unattended power plant, it should comprise an undervoltage element and an associated time delay. Settings must be chosen to avoid maloperation during the inevitable voltage dips during power system fault clearance or associated with motor starting. Transient reductions in voltage down to 80% or less may be encountered during motor starting.
3.		General comments for C37.102 Page 71, 4.5.7.2	Where undervoltage protection is required, the undervoltage function should never trip for any transmission system fault condition.
4.		General comments for C37.102 Page 71, 4.5.7.2	The following coordination need to be considered while performing generator under voltage relay setting: 1-The Transmission Owner needs to provide the longest clearing time and reclosing times for faults on transmission system elements connected to the high-side bus. 2- If undervoltage tripping is used for the generator and an Undervoltage Load Shedding (UVLS) program is used in the

			transmission system, the UVLS set points and time delays must be coordinated with the generator undervoltage trips. 3- The Generator Owner needs to provide relay set point and time delay to the Transmission Owner; the generator set points should be modeled in system studies to verify coordination. A simple relay-to-relay setting coordination is inadequate due to differences in voltage between the generator terminals and transmission or distribution buses where the UVLS protection is implemented. 4- This coordination should be validated by both the Generator Owner and Transmission Owner. This relay shall be set at the minimum permissible operating voltage and time delayed to allow transient undervoltage originated by sudden increase of loads, motor starting or by transmission system fault conditions. A time delay is necessary to override situations that can be adequately regulated by the automatic excitation system. Generator protection settings for generators connected to power system have to be validated in light of Voltage ride through (VRT) requirement. This shall be achieved by coordination of voltage duration profile or voltage duration envelop for the power system with power plant protections. Generation and other system plant would be expected to remain connected for voltages within the voltage duration profile.
4.	Page 50, 3.3.1.2.1.2. Tripping for Faults (not recommended, except as noted above)	Utilize the 27 undervoltage function for tripping with a maximum setting of 0.9 pu for pickup and with a minimum time delay of 10 seconds.	From C37.102, it appears 27 is picked up when voltage is above a setting voltage and dropped out when voltage is below the setting voltage. At Basler, we say 27 is picked up when voltage is below the setting voltage and dropped out when voltage is above the setting voltage.
	32- Reverse Power Protection		
1.	Page 69	Reverse power protection is applied to prevent….	Provide a statement about CTG and Hydro as is done C37.102 page 68 Suggest – Combustion turbine and hydro generators may permit motoring during start-up or during pump/storage mode
	40-Loss of Field		
1.		General Comment	Propose: 1) Discuss the need to coordinate with the Planning Coordinator and Transmission Owner (borrowing from the NERC document). 2) While Machine Capability Curve can be passed temporarily, Steady-State Stability Limit cannot. (Figure 4-38)

			3) In the 40 setting example, zone 1 and zone 2 time delays are different between NERC document and C37.102. C37.102 may add an undervoltage supervision to 40.
2.		General Comment	At next revision of C37.102, recommend adding results of an actual stability study with impedance trajectories of both stable & unstable swings: 1. Specifically, the stable swing trajectory should be plotted and timed for its location within the LOF characteristic a. Show how the initially chosen time delay either coordinates with the stable swing or not b. State how much margin in cycles would be necessary before the time delay would be adjusted. 2. For an unstable swing, demonstrate how the trajectory passes through the LOF characteristic a. State whether or not it is acceptable for the LOF element to trip for this condition b. Demonstrate how the LOF element would coordinate with an actual 78 OOS element (time delay) It is my view that it is critical to show examples of how the LOF protection settings are adjusted from their initial “cookbook” settings to coordinate with stable/unstable power swings.
3.	From C37.102, Page 55, 1st paragraph	“The dropout level of this undervoltage relay would be set at 90% to 95% of rated voltage, and the relay would be connected to block tripping when it is picked up and to permit tripping when it drops out.” I was a little confused.	It appears 27 is picked up when voltage is above a setting voltage and dropped out when voltage is below the setting voltage. We say 27 is picked up when voltage is below the setting voltage and dropped out when voltage is above the setting voltage. Clarify pickup to be consistent with other functions.
4.	Page 73, Figure 3.5.1	Figure 3.5.1 - R-X plot showing two zones of 40 against impedance trajectories for heavy & light load, machine capability curve, MEL, & condensing (if applicable) - similar to C37.102-2006 figures 4-36 to 4-38.	Is this figure more/less informative than C37.102-2006 figures 4-36 to 4-38?
5.	Page 74, Section 3.5.2.1 Coordination of Generator and Transmission System/Faults	From the following two statements: The GO demonstrates “that these impedance trajectories [for fault clearing] coordinate” with the LOF time delay “If there is an out-of-step protection installed it should be	It is unclear how any of this could be demonstrated short of system stability studies (although the NERC paper only states that such studies “may” be required). C37.102-2006 states (Section 4.5.1.3, page 51): “Time delay of

		coordinated with the LOF protection." The implication is that the LOF protection will not operate for any machine swing (stable or unstable) resulting from worst-case fault clearing. It is unclear how any of this could be demonstrated short of system stability studies (although the NERC paper only states that such studies "may" be required). C37.102-2006 states (Section 4.5.1.3, page 51): "Time delay of 0.5 s to 0.6s would be used with this unit in order to prevent possible incorrect operations on stable swings. Transient stability studies are used to determine the proper time-delay setting."	0.5 s to 0.6 s would be used with this unit in order to prevent possible incorrect operations on stable swings. Transient stability studies are used to determine the proper time-delay setting." Resolve two positions with emphasis on including need for stability studies.
6.	Page 74, Section 3.5.2.2 Loadability	Coordination with MEL/machine capability demonstrated. For LOF properly coordinated, it is unclear how the LOF characteristic could encroach upon an operating load point described in steps 2 and 3, since the MEL would be expected to operate first (except in the case of MEL malfunction, in which case the LOF protection would be expected to operate).	C37.102 to review comment
7.	Page 75, Section 3.5.3 Considerations and Issues	o Coordinate with GCC/MEL and SSSL o Don't trip for stable swings; periodically verify with stability studies o Prevent cascading ("small amount of generation... as a percentage of the load in the affected portion of the system"). Add protection models to stability models to simulate loss of generation by LOF that cannot be coordinated.	Coordinate with GCC/MEL (already mentioned) and SSSL Don't trip for stable swings (already mentioned); periodically verify with stability studies (other way(s) to verify?) Prevent cascading ("small amount of generation... as a percentage of the load in the affected portion of the system"). Add protection models to stability models to simulate loss of generation by LOF that cannot be coordinated.
8.	Page 76, Section 3.5.4 Coordination Considerations	LOF don't trip before MEL (already mentioned), adequate margin. Determine if MEL allows "quick change of Q beyond the limit" Coordinate with SSSL (already mentioned), especially if AVR in manual	C37.102 to review comment

		Relay characteristics can change with variation in frequency Consider for hydro units (110% of nominal speed while islanded) • C37.102-2006 Section X page Y: F>60Hz, MTA into 4th quad, diameter increase 200-300% • Supervise with UV (0.8-0.9pu) or OF (110% rated freq) • 0.25-1s delay C37.102-2006 Section 4.5.1.3 page 55: "A system separation that leaves transmission lines connected to a hydrogenerator may also cause unnecessary operation of the distance relay schemes. For this condition, the hydrogenerator may temporarily reach speeds and frequencies up to 200% of normal. It may not be desirable to trip for this condition. At frequencies above 60 Hz, the angle of maximum torque for some distance relays will shift farther into the fourth quadrant and the circle diameter may increase by 200% to 300%. With this shift and increase in characteristic, it is possible for the relay to operate on the increased line charging current caused by the temporary overspeed and overvoltage condition. Unnecessary operation of the distance relay schemes for this condition may be prevented by supervising the schemes with either an undervoltage relay or an overfrequency relay. The undervoltage relay would be set and connected as previously discussed. The overfrequency relay would be set to pick up at 110% of rated frequency and would be connected to block tripping when it is picked up and to permit tripping when it resets." Single zone/dual zone time delay - should	

		not operate during stable swings (already mentioned). Timers - fast reset strongest source (all ties closed), weakest credible, blackstart	
9.	Page 78, Section 3.5.5 Example	Two-zone example stable swing incursion into LOF zone 1 (check time delay) Study stable swings with weak system refers to PSRC J5 paper "Coordination of Generator Protection with Generator Excitation Control and Generator Capability" C37.102-2006 Section A.2.1 Coordinate with GCC/UEL/SSSL	C37.102 to review comment
	46-Negative Sequence		
1.	Page 10, Table 2, Page 15, Table 3, Page 83,3.6.2.1	Coordinate 46 with line protection for all unbalanced faults	Consider modifying annex wording in A2.8, page 148 to include: "…should be coordinated with system phase <u>and ground</u> fault protection. The 46 function should not operate faster than the ~~primary~~ system phase <u>and ground</u> fault protection <u>including breaker failure time</u> while still protecting the generator."
2.	Page 83, 3.6.2.1	Single pole tripping or other open-phase conditions.	Add: "Avoid operation of 46 alarm and trip function during sustained open-phase conditions such as single-pole tripping or an open pole on a disconnect switch or circuit breaker unless required to protect the generator."
	50/27-Inadvertent Energizing Protection		
1.	Page 89, 3.7.2.1	…voltage supervision pick-up is 50% or less, as recommended by C37.102	none, already covered
2.	Page 89, 3.7.2.1	It is highly desirable to remove the protection from service when the unit is synchronized to the system…	make sure the recommendation is in the Guide
3.	Page 89, 3.7.2.1	The inadvertent energizing protection must be in service when the generator is out-of-service	make sure this caveat is in the Guide
	50BF-Breaker Failure		
1.	Page 93, 3.8.1	"breaker failure timer is initiated by… a protective relay and…either a current detector or a breaker "a" switch…"	No addition needed. This description is a quote from Section 4.7 of C37.102
2.	Page 96, 3.8.2.1	"All generator unit backup relaying schemes are required to coordinate with protective	Revise Section 4.6 of C37.102 to note this detail.

		relays on the next zone of protection including breaker failure protection.”	
3.	Page 96, 3.8.3	Total clearing time, which includes breaker failure time, of each breaker in the generation station substation should coordinate with critical clearing times associated with unit stability." Note: The discussion of Critical Clearing Time is only relevant if there are nearby units where stability is compromised by a fault in the generating unit. The unit with the fault is tripping and the only consideration is rapid clearing to limit equipment damage. The document seems to be mixing the discussion of BF timing of transmission breakers for line faults, where we are trying to preserve the operating unit, and faults inside the generating station, where the unit is being tripped.	Revise Section 4.7 of C37.102 to add this detail Clarify Critical Clearing Time discussion in Section 3.8.3 of the TRD. Add a similar clarification to Section 4.7 of C37.102.
4.	Page 99, 3.8.5.2	“Improper coordination results when upstream protective functions react faster than the breaker failure functions.”	Revise Section 4.7 of C37.102 to add this detail.
5.	Page 94, Figure 3.8.1	In Figure 3.8.1, the 50BF-G CT is in the generator neutral, which may not correctly indicate if the breaker is open. A phase fault in the generator will cause a BF operation even if the 52G breaker opens properly since the generator fault current continues until the field is gone. The logic diagram in this figure requires both the 52A contact open and the 50BF-G fault detector to be reset. If the CT is used in the location shown, only the 52A contact can be used for breaker position, which is not the best alternative.	Revise Section 4.7 of C37.102 to add a clarification to specify the CT must measure the breaker current
	51T-Generator Step-Up Phase Overcurrent Protection	none	
	51V Voltage-Controlled or Voltage-Restrained Overcurrent Protection		

1.	Page 118, 3.10.4.2	"Note this is (V_G) less than 10% of rated generator terminal voltage. This voltage will be higher if the generator was loaded prior to the fault and/or if the voltage regulator is in service. However, even with the regulator in service, the generator current and voltage will be limited by the excitation system ceiling voltage. This is typically between 1.5 times to 2 times the rated exciter voltage. Thus, generator voltage will still be greatly reduced below normal for a fault at the output terminals of the transformer". 51V element operates for phase to phase and three phase faults so that, the limiting case for maximum fault system voltage should be considered phase to phase faults and not the three phase faults.	Annex A.2.6; The under voltage element should be set no lower than 125% of the maximum fault voltage (calculated with the automatic voltage regulator at full boost and the generator was loaded prior to fault).
2.	Page 116, 3.10.3	It should be noted that where VT type static exciters are used, the generator fault current may decay quite rapidly when there is low voltage at the generator terminals due to a fault. As a consequence, the overcurrent type of phase fault backup relay with long time delays may not operate for system faults. Therefore, the performance of these relays should be checked with the fault current decrement curve for a particular generator and VT static excitation system.	Recommendation to C37.102 Item 4.6.3 Settings: If 51 V functions are to apply to a self-excited system, performance of relays should be checked with the fault current decrement curve; Alternatively a power current transformer could be included to boost excitation during fault conditions. The supplemental excitation provided by the PCT should be sufficient to maintain fault current at a level that will facilitate overcurrent tripping. Without such CTs, fault clearing for a primary protection failure becomes a race between the collapsing fault current and the backup relay's time–current characteristic.
3.	Page 19, 3.1.1	Note that Function 21 (TRD Section 3.1.1) is another method of providing backup for system faults, and it is never appropriate to enable both Function 21 and Function 51V. This statement is not clearly stated on C37.102. Even in Annex A. both protection functions were enabled without referring to this recommendation.	Recommendation to IEEE C37.102 paragraph 4.6 1- The transmission system is usually protected with phase distance (impedance) relays. Time coordination is attained between distance relays using definite time settings. The 51V functions have varying time delays based on their time versus current time to operate curves. Time coordinating a 51V and a 21 lends to longer clearing times at lower currents. The 51V functions are often used effectively on generator connected to distribution system where distribution feeders are protected with time inverse characteristic relays. For these reasons, it is recommended that an impedance function be used rather than a

			51V function for generators connected to the transmission system. 2- It is never appropriate to enable both Function 21 and Function 51V. If transmission system uses both types of protections, then the backup can be chosen as the distance function).
4.	Page 113, 3.10.1	Its function is to provide backup protection for system faults when the power system to which the generator is connected is protected by time-current coordinated protections. It is common practice to provide protective relaying that will detect and operate for system faults external to the generator zone that are not cleared due to some failure of system protective equipment. This protection generally referred to as system backup.	Recommendation to 4.6: Backup fault protection is recommended to protect the generator from the effects of faults that are not cleared because of failures within the normal protection scheme. The backup relaying can be applied to provide protection in the event of a failure at the generation station, on the transmission system, or both. Specific generating station failures would include the failure of the generator or GSU transformer differential scheme. On the transmission system, failures would include the line protection relay scheme or the failure of a line breaker to interrupt.
5.	Page 118, 3.10.4	To assess a 51V over current relay's response to time-varying currents such as a generator fault, the relay's dynamic characteristic must be used. C37.112 provides mathematical definitions for both the steady-state (TCC) and dynamic relay characteristics. The coordination of voltage restrained time over current relays with directional overcurrent 67 is usually based on static characteristics in which the time-current plots assume constant current. This assumption greatly simplifies the coordination process but fails to account for the slow-down effect due to the decrement in generator fault currents. Voltage restrained over current can be practically coordinated with normal overcurrent relays under simplifying assumptions. The resulting coordination plots are valid for close-in faults. Distant faults, for which the 51V is applied to provide backup protection, have significantly longer trip times than suggested by the simplified coordination method. The rapid trip time increase with increasing external impedance limits the reach of the 51V relay to a shorter distance than the limit obtained by	4.6: Address the dynamic relay response to transient currents when coordinating 51VR with directional overcurrent 67 installed on transmission system.

		considering the constant transient current. This fact must be taken into account when determining the zones of protection. In other words, the 51V may not provide the backup protection in the entire assumed zone of protection. Also, it was shown that field forcing extends the reach of the 51V relay. This is one of the benefits of static excitation.	
6.	Page 115, 3.10.2.2	After the overcurrent tap setting is chosen, a time delay can be chosen. The 51 V is a backup function and should not operate unless a primary relay fails. As such, the time delay chosen should provide ample margin to assure coordination with normal relaying. The delay must not exceed the generator short time thermal capability as defined by IEEE C50.13 or the transformer through fault protection curve as per IEEE C37.91 Annex A.	Recommendation to 4.6.3: After the overcurrent tap setting is chosen, a time delay can be chosen. The 51 V is a backup function and should not operate unless a primary relay fails. As such, the time delay chosen should provide ample margin to assure coordination with normal relaying. The delay must not exceed the generator short time thermal capability as defined by IEEE C50.13 or the transformer through fault protection curve as per IEEE C37.91 Annex A.
7.	Page 116, 3.10.3	From TRD 3.10.3, “The 51V has a very slow operating time for multi-phase faults. This may lead to local system instability resulting in the tripping of generators in the area. A “Zone 1” impedance function would be recommended in its place to avoid instability as stated in C37.102.”	Consider including this issue in C37.102 if it is not addressed already.
8.	Page 118, 3.10.4.1.1	Voltage-Controlled Overcurrent Function (51VC): The overcurrent pickup is usually set at 50 percent of generator full load current as determined by maximum real power out and exciter at maximum field forcing. For a three-phase fault at the output terminals of the transformer, the steady-state fault current (CT secondary) may be calculated by the following equivalent circuit (see C37.102 Figure A.15). In order to find the lowest fault current, it is assumed that the automatic voltage regulator is off-line and the generator was not loaded prior to fault.	Annex A.2.6: It is recommended that the relay’s current pickup setting should not exceed 80% of the minimum fault current (calculated with the manual regulator in service the generator was not loaded prior to fault).
9.	Page 113, 3.10.1	Proposed to revise the definition of back up	Backup fault protection is recommended to protect the generator

		fault protection in TRD as well as IEEE C37.102 as described	from the effects of faults that are not cleared because of failures within the normal protection scheme. The backup relaying can be applied to provide protection in the event of a failure at the generation station, on the transmission system, or both. Specific generating station failures would include the failure of the generator or GSU transformer differential scheme. On the transmission system, failures would include the line protection relay scheme or the failure of a line breaker to interrupt. This applies to descrete relays, but not to functions within a single microprocessor relay.
	59GN-27TH	none	
	59 Overvoltage Protection		
1.	Page 124, 3.11	A sustained overvoltage condition beyond 105 percent normally should not occur for a generator with a healthy voltage regulator, but it may be caused by the following contingencies; (1) defective automatic voltage regulator (AVR) operation, (2) manual operation without the voltage regulator in-service, and (3) sudden load loss.	IEEE Standard C37.102 -2006, "Guide for AC Generator Protection," The guide only talks about sudden load loss as a cause of overvoltage. The wording from the NERC TRD should be incorporated into the guide.
	78-Out of Step Protection	none	
	81 O/U-Abnormal Frequency Protection		
2.	Pages 150-151, 3.14.4	Proper coordination of turbine UF protection and system UFLS must be checked by the Planning Coordination and Generator Owner. This must include simulating performance of the turbine UF protection within the dynamic studies performed by the Planning Coordinator when they evaluate the system UFLS scheme. It is not as simple as the coordination example provided in TRD Section 3.14.5. An actual example of such a PC evaluation of system UFLS against turbine UF protection would be helpful.	C37.102 has a good example in the Appendix A.2.14.1. Still, it should be noted that a dynamic study must be done to confirm the coordination.
3.	Pages 151-152, 3.14.5.1	The TRD notes that the coordination between turbine UF protection and system	Add wording to C37.102 (especially in Appendix A.2.14.1) and/or C37.106 to more clearly state that coordination is "*not a*

		UFLS is "*not a relay-to-relay coordination in the traditional sense; rather, it is coordination between the generator prime mover capabilities, the overfrequency and underfrequency protection, and the UFLS program and transmission system design.*" (TRD page 148 section 3.14.2.3) Because of this, the coordination plot provided in TRD Figure 3.14.3 on page 152 does not guarantee adequate coordination between turbine UF protection and the system UFLS scheme. It only illustrates coordination between turbine UF limits and UF protection. No mention of the system UFLS scheme or turbine UF limits are made. To me this makes TRD Section 3.14.5.1 misleading.	*relay-to-relay coordination in the traditional sense; rather, it is coordination between the generator prime mover capabilities, the overfrequency and underfrequency protection, and the UFLS program and transmission system design.*"
	87G, 87T and 87U Differential Protection	none	

Comments to be addressed by: IEEE C37.106

	Location in NERC TRD (Page Number and Subsection)	**Relevant Issues**	**Proposed Addition to specific IEEE Guides**
1.	Pages 151-152, 3.14.5.1	The TRD notes that the coordination between turbine UF protection and system UFLS is "*not a relay-to-relay coordination in the traditional sense; rather, it is coordination between the generator prime mover capabilities, the overfrequency and underfrequency protection, and the UFLS program and transmission system design.*" (TRD page 148 section 3.14.2.3) Because of this, the coordination plot provided in TRD Figure 3.14.3 on page 152 does not guarantee adequate coordination between turbine UF protection and the system UFLS scheme. It only illustrates coordination between turbine UF limits and UF protection. No mention of the system UFLS scheme or turbine UF limits are made. To me this makes TRD Section 3.14.5.1 misleading.	Add wording to C37.102 (especially in Appendix A.2.14.1) and/or C37.106 to more clearly state that coordination is "*not a relay-to-relay coordination in the traditional sense; rather, it is coordination between the generator prime mover capabilities, the overfrequency and underfrequency protection, and the UFLS program and transmission system design.*"

Working Group J3 – Power Plant and Transmission System Protection Coordination
Review of NERC Technical Reference Document - Power Plant and Transmission System Protection Coordination

Comments to be addressed by: NERC Technical Reference Document

	Location in NERC TRD (Page Number and Subsection)	**Relevant Issues**	**Proposed Addition**
	21-Phase Distance Protection		
1.	Page. 19, Sec 3.1.1	"…is to provide backup protection for system faults…"	Intent of the 21 function is to provide backup protection for system **multi-phase** faults. Backup up to system ground faults should be provided by other means.
2.	Page. 20, Sec 3.1.1	"If the generator is over-protected, meaning that the impedance function can operate when the generator is not at risk…"	This may be better worded.
3.	Page. 26, Sec 3.1.3	"…methods such as out-of-step blocking should be incorporated into impedance function tripping logic to assure the function will not operate for stable swings."	Poor wording here? Out-of-step implies unstable swing. Should it say blinders rather than out-of-step blocking? As far as I know, out-of-step blocking is typically not part of generator protective function. C37.102 WG to discuss out-of-step blocking. Also refer to the section on out of step tripping to tie the two together.
4.	Various pages and section	"…backup protection should be provided for transmission system relay failure."	It should say "transmission system protection failure" which is more than relay failure. This includes relay failure, breaker failure, instrument transformer failure, etc.
	24-Volts per Hertz		
1.	Page 40, Sec 3.2	Section 3.2 of the NERC TRD includes much discussion on the coordination aspects of Device 24 – Overexcitation Protection, or Volts per Hertz. Typically, generators will be damaged if V/Hz exceeds 105% of the generator's rated voltage divided by its rated frequency. Also, any GSU or unit auxiliary transformer connected to the generator terminals will be damaged if V/Hz exceeds 105% of the transformer's rated voltage divided by its rated frequency at full load and 0.8 pf, or 110% if unloaded. Device 24	The TRD should consider including the following: 1. A discussion of the dynamic and largely subjective nature of UF events. The UFLS programs are based on simulation studies, which make many assumptions that are not all based on direct empirical data. The programs shed multiple blocks of load at different stages of declining frequency. As each block of load is shed, it may not be sufficient to arrest the frequency decline, and the system may continue to the next stage of the UFLS program. Or it may be more than sufficient leading to a frequency overshoot, causing mechanical overspeed tripping of generators, making them unavailable for restoring the system. A third possibility is that the frequency may stabilize at a reduced level for an extended period,

		protection is applied to protect these elements from excessive V/Hz. The reason this may be a concern for power plant/transmission system coordination is that the generator/GSU unit may be tripped unexpectedly if system voltage and frequency is not maintained within these limits during system disturbances which result in underfrequency or overvoltage. And if an underfrequency (UF) event is already occurring, generator trips will only make it worse, possibly leading to total system collapse.	which could result in machines accumulating some hidden damage, even though the V/Hz protection doesn't operate. 2. A discussion of the data that needs to be exchanged between the entities involved. 3. A discussion of the importance of controlling reactive elements such as capacitor banks and reactors to prevent overvoltage or undervoltage during a UF event. 4. The importance of time delays in the various active elements. Protective devices must be set with adequate margin to ensure equipment protection, while providing as much time as possible for the UFLS program to operate. 5. The importance of stability studies to validate coordination. If tripping of some generators cannot be avoided, the UFLS program may need to be revised to accommodate the loss. 6. Islands – system separation is the most probable cause of frequency and voltage excursions within a large interconnection. 7. Coordination procedure – recommendations and examples for achieving coordination.
	Page. 42, 3.2.5	What about hydro plants? They can handle wide frequency deviations but not sure about V/Hz - the GSU would have the same issues anywhere it was placed.	Add comments for hydro plants.
	27-Undervoltage		
1.	Page. 54, 3.3.2	Power plant station service is an area where this condition may exist. During a system disturbance that reduces voltage, the system may separate and completely collapse upon additional loss of generation capacity, which can occur if the motors drop out on undervoltage. The successful recovery of the system depends on maintaining each unit at maximum possible capability. In this case, the fans, pumps, etc. that serve the unit must remain in operation, even though the voltage is reduced below a normally designated safe value. Recovery can then be accomplished by suitable operator action.	When a motor is not considered essential, the undervoltage device may be connected to trip the appropriate contactor or circuit breaker where tripping is allowed.
	32- Reverse Power Protection		
1.	Page 69, Fig 3.4.1	Location of 32 device	Refer to Fig 7-1a on page 109 of C37.102 to place the CT on the

			output terminal of the generator, VT location is correct and should be to the right of the relocated CT position.
2.	Page 65	Quoted material is one large applied to prevent…	Split paragraph as is done on page 68 of C37.102
3.	Page 65	Reverse power protection is applied to prevent….	Provide a statement about CTG and Hydro as is done C37.102 page 68 Suggest – Combustion turbine and hydro generators may permit motoring during start-up or during pump/storage mode
4.	Page 67	Table 2 System concerns typo of Var	correct to type as lower case var
	40-Loss of Field	none	
1.	Page 72, 3.5.1. Purpose of the Generator Function 40 — Loss-of- Field Protection	Section 3.5.1 begins with an apparent quote of sections 4.5.1, 4.5.1.1 of C37.102- 2006.	Although they appear to be quotes, closer examination reveals that they are not direct quotes (more of a paraphrase). "A loss of field condition causes devastating impact on the power system as a loss of reactive power support from a generator as well as creating a substantial power drain from the system." • This sentence is not in C37.102-2006 and is only true in certain cases for large machines, not for smaller machines (<300MW). C37.102-2006: "With regard to effects on the system, the var drain from the system may depress system voltages and thereby affect the performance of generators in the same station, or elsewhere on the system. In addition, the increased reactive flow across the system may cause voltage reduction and/or tripping of transmission lines and thereby adversely affect system stability." The "quote" refers to figures 3.4.1 & 3.4.2, neither are they valid for the NERC document itself, which are not present in C37.102-2006 or C37.102- 1995. Not sure where these words originated.
2.	From C37.102, Page 55, 1st paragraph	"The dropout level of this undervoltage relay would be set at 90% to 95% of rated voltage, and the relay would be connected to block tripping when it is picked up and to permit tripping when it drops out." I was a little confused.	It appears 27 is picked up when voltage is above a setting voltage and dropped out when voltage is below the setting voltage. We say 27 is picked up when voltage is below the setting voltage and dropped out when voltage is above the setting voltage. Clarify pickup to be consistent with other functions.
3.	Page 74, Section 3.5.2.1 Coordination of Generator and Transmission System/Faults	From the following two statements: The GO demonstrates "that these impedance trajectories [for fault clearing] coordinate" with the LOF time delay "If there is an out-of-step protection installed it should be coordinated with the LOF protection." The implication is that the LOF protection will not operate for any machine swing (stable or	It is unclear how any of this could be demonstrated short of system stability studies (although the NERC paper only states that such studies "may" be required). C37.102-2006 states (Section 4.5.1.3, page 51): "Time delay of 0.5 s to 0.6 s would be used with this unit in order to prevent possible incorrect operations on stable swings. Transient stability studies are used to determine the proper time-delay setting."

		unstable) resulting from worst-case fault clearing. It is unclear how any of this could be demonstrated short of system stability studies (although the NERC paper only states that such studies “may” be required). C37.102-2006 states (Section 4.5.1.3, page 51): “Time delay of 0.5 s to 0.6s would be used with this unit in order to prevent possible incorrect operations on stable swings. Transient stability studies are used to determine the proper time-delay setting.”	Resolve two positions with emphasis on including need for stability studies.
	46-Negative Sequence		
1.	Page 83, 3.6.2.1	Single pole tripping or other open-phase conditions.	Add: “Avoid operation of 46 alarm and trip function during sustained open-phase conditions such as single-pole tripping or an open pole on a disconnect switch or circuit breaker unless required to protect the generator.”
	50BF-Breaker Failure		
1.	Page 98, 3.8.5	Section 3.8.5 seems like it would fit better in Section 3.1 on Backup Protection. This example describes 21 coordination for transmission line breakers (which is covered in Section 3.1) rather than generator 52G or 52T BF protection.	Consider moving Section 3.8.5 to Section 3.1 of the TRD. Based on the wording in Section 3.8.1, Section 3.8 seems to be a discussion of 52G or 52T BF protection.
5.	Page 94, Figure 3.8.1	In Figure 3.8.1, the 50BF-G CT is in the generator neutral, which may not correctly indicate if the breaker is open. A phase fault in the generator will cause a BF operation even if the 52G breaker opens properly since the generator fault current continues until the field is gone. The logic diagram in this figure requires both the 52A contact open and the 50BF-G fault detector to be reset. If the CT is used in the location shown, only the 52A contact can be used for breaker position, which is not the best alternative.	Modify Figure 3.8.1 in the TRD to show the CT on the GSU side of the 52G breaker. Add a clarification in Section 3.8.1 of the TRD to specify the CT must measure the breaker current.
	51T-Generator Step-Up Phase Overcurrent Protection		

1.	Page 102, 3.9.1.1	"The use of 51T phase overcurrent protection for the generator step-up transformer phase overcurrent protection is STRONGLY discouraged due to coordination issues that are associated with fault sensing requirements in the 0.5 second or longer time frame"	C37.91-2008, Annex A – Application of the transformer through-fault-current duration guide to the protection of power transformers discusses the use of transformer phase overcurrent protection (51T). Propose TRD wording be revised to read: "The use of 51T phase overcurrent protection for the generator step-up transformer phase overcurrent protection is STRONGLY discouraged due to coordination issues that are associated with fault sensing requirements in the 0.5 second or longer time frame. However, the 51T can be applied to provide transformer through-fault-current winding protection per C37.91-2008, Annex A and section 3.9.4 of this document."
2.	Page 103, 3.9.2.1	Use of generator step-up transformer phase over current function (51T) for backup function is strongly discouraged.	Feedback to NERC: The above statement downplays the importance of that protection. This protective function provides a vital backup role in the back-feed mode for generators with medium voltage generator breakers. In this scenario the aux transformer is back-fed during outages and during start-up. For faults on iso-phase this will be only backup protection. Feedback to NERC: 51T should be set as high as possible just below transformer thermal damage curve (approximately through fault damage current capability is 2 seconds) so that it will be relatively slow and will be relatively easy to coordinate with worst case transmission protection- (51T should always operate slower than transmission protection)
	51V Voltage-Controlled or Voltage-Restrained Overcurrent Protection		
1.	Page 120, 3.10.4.2. Setting Considerations	<u>Existing IEEE C37.102-2006 Annex A.2.6</u> "Note this is (V_G) less than 10% of rated generator terminal voltage. This voltage will be higher if the generator was loaded prior to the fault and/or if the voltage regulator is in service. However, even with the regulator in service, the generator current and voltage will be limited by the excitation system ceiling voltage. This is typically between 1.5 times to 2 times the rated exciter voltage. Thus, generator voltage will still be greatly reduced below normal for a fault at the output terminals of the transformer". 51V element operates for phase to phase and three	The following could be added to NERC TRD "Typically, a generator's excitation system is capable of delivering ceiling voltage of 1.5 to 2 times rated exciter voltage required for full load operation. The excitation boost is a benefit for the over current element of either type of 51 V function, but if there is impedance between the generator and the fault, the increased field current will also significantly increase the generator terminal voltage. The effect will be to desensitize the voltage-restrained relay, or possibly prevent the dropout of the under voltage element of the voltage-controlled relay. Consequently, setting calculations are not only required to establish the minimum fault current conditions, but also maximum fault voltage conditions. More fault voltage will appear if the fault is an arcing fault or far from transformer terminals.

		phase faults so that, the limiting case for maximum fault system voltage should be considered phase to phase faults and not the three phase faults.	51V element operates for phase to phase and three phase faults so that, the limiting case for maximum fault system voltage should be considered phase to phase faults and not the three phase faults”. Recommendation: “The under voltage element should be set no lower than 125% of the maximum fault voltage (calculated with the automatic voltage regulator at full boost and the generator was loaded prior to fault”.
2.	New 3.10.3.2 Special Consideration for units with self excited generators	Propose to add a recommendation for self excited units at TRD as described , the concern was already addressed in IEEE C37.102 but we can add the recommendation to use PCT.	The following could be added to NERC TRD “51V Application problems associated with self-excited units: These systems take excitation power from the generator terminals using power potential transformers (PPTs). Faults cause a reduction in terminal voltage that in turn reduces the available excitation voltage. If the resulting excitation is insufficient to support the fault current, the excitation will collapse and fault current will decay to near zero. The greater the impedance between the fault and the generator terminals, the higher the terminal voltage and the more likely the system is to sustain fault current. A complete collapse would certainly occur for a three-phase fault at the generator terminals. Phase-to-phase faults and phase-to-ground faults would retain some voltage on the un faulted phases, but this voltage is generally not sufficient to maintain fault current at a level suitable for overcurrent tripping”. If 51 V functions are to apply to a self-excited system, performance of relays should be checked with the fault current decrement curve; Alternatively a power current transformer could be included to boost excitation during fault conditions. The supplemental excitation provided by the PCT should be sufficient to maintain fault current at a level that will facilitate overcurrent tripping. Without such CTs, fault clearing for a primary protection failure becomes a race between the collapsing fault current and the backup relay’s time–current characteristic.
3.	Page 113, 3.10.1	Proposed to revise the definition of back up fault protection in TRD as well as IEEE C37.102 as described	Backup fault protection is recommended to protect the generator from the effects of faults that are not cleared because of failures within the normal protection scheme. The backup relaying can be applied to provide protection in the event of a failure at the generation station, on the transmission system, or both. Specific generating station failures would include the failure of the generator or GSU transformer differential scheme. On the transmission system, failures would include the line protection relay scheme or the failure of a line breaker

			to interrupt. This applies to discrete relays, but not to functions within a single microprocessor relay.
4.	Page 114, 3.10.2.1. Faults	The Generator Owner and Transmission Owner need to exchange the following data: Generator Owner-Unit ratings, subtransient, transient, and synchronous reactance and time constants, Station one line diagrams 51V- C or 51V-R relay type, CT ratio, VT ratio, Relay settings and setting criteria, Coordination curves for faults in the transmission system up to two buses away from the generator high voltage bus	Add negative sequence and zero sequence to ‘Unit ratings, subtransient, transient, and synchronous reactance and time constants”
5.	Page 116, 3.10.3. Considerations and Issues	For trip dependability within the protected zone, the current portion of the function must be set using fault currents obtained by modeling the generator reactance as its synchronous reactance. This very well means that to set the current portion of the function to detect faults within the protected zone, the minimum pickup of the current function will be less than maximum machine load current.	The maximum reach is determined by using synchronous reactance, however to obtain maximum reach for “downstream” devices the generator subtransient reactance should be used to ensure the worst case coordination margin between the 51V and transmission line protection devices.
6.	Page 116, 3.10.3. Considerations and Issues	“The transmission system is usually protected with phase distance (impedance) relays. Time coordination is attained between distance relays using definite time settings. The 51V functions have varying time delays based on their time versus current time to operate curves. Time coordinating a 51V and a 21 lends to longer clearing times at lower currents. The 51V functions are often used effectively on generator connected to distribution system where distribution feeders are protected with time inverse characteristic relays. For these reasons, it is recommended that an impedance function be used rather than a 51V function for generators connected to the transmission system.”	Delete: “For these reasons, it is recommended that an impedance function be used rather than a 51V function for generators connected to the transmission system.” The substance of this paragraph is correct, however a 51V element can be used effectively on transmission lines with overcurrent protection. The NERC TRD should be revised to include this clarification.
7.	Page 117, 3.10.3.	The voltage function of the 51V-C is set 0.75	This part of the paragraph needs to be addressed/rewritten. There

	Considerations and Issues	per unit voltage or less to avoid operation for extreme system contingencies. A fault study must be performed to assure that this setting has reasonable margin for the faults that are to be cleared by the 51V. Backup clearing of system faults is not totally dependent on a 51V function (or 21 function). Clearing of unbalanced multi-phase faults can be achieved by the negative sequence function. Clearing of three-phase faults can be achieved by the overfrequency and overspeed tripping functions. The 51V function provides minimal transmission system backup protection for relay failure. It must not be relied upon to operate to complete an isolation of a system fault when a circuit breaker fails to operate as it does not have enough sensitivity. The 51V has a very slow operating time for multi-phase faults. This may lead to local system instability resulting in the tripping of generators in the area. A “zone 1” impedance function would be recommended in its place to avoid instability as stated in C37.102. Voltage functions must be set less than extreme system contingency voltages or the voltage-controlled function will trip under load. The voltage-restrained function time to operate is variable dependent on voltage.	are many instances where a 51V relay is the primary protection to ensure a generator trips for a line fault, (ie generators supplied by a dedicated tie line, or applications with multiple units where the units can be operated independently). As a general rule voltage and frequency are used to maintain system integrity and can be influenced by system loading, and prime-mover governor characteristics, they should not be used as primary fault detection and clearing. It is true the slowest worst case fault is a 3 phase fault which drives the generator into the synchronous region, however the minimum pick-up and TD settings can be adjusted increase the tripping speed. For a L-L fault the generator negative sequence reactance (typically similar to X’d) would dominate allowing the 51V to operate relatively quickly, this fault should be used for the worst case coordination for “downstream” protective devices. A Zone-1 distance element used to detect line faults would lead to miscoordination with the transmission line and bus differential relays, it should not be set to clear for line faults. Zone-1 distance elements could be set to look into the GSU to provide backup transformer protection, however the element should be set no higher than 67%of the GSU impedance and have a 5 – 6 cycle time delay to allow time for the primary protection to clear the fault in order to provide for ease of fault locating.
8.	Page 117, 3.10.3. Considerations and Issues	For generators connected to the transmission system utilizing distance protection functions, the 21 function is recommended over the 51V function. It is not necessary to have both functions enabled in a multi-function relay. The 21 function can clearly define its zone of protection and clearly define its time to operate and therefore coordinate better with transmission system distance protection functions.	This is generally true, however if the transmission relays are phase time overcurrent elements a 51V relay may be the best alternative.
9.	Page 118, 3.10.4	(I propose to highlight the dynamic relay	The following could be added:

		response to transient current as described)	Dynamic Relay Response to Transient Current To assess a 51V over current relay's response to time-varying currents such as a generator fault, the relay's dynamic characteristic must be used. C37.112 provides mathematical definitions for both the steady-state (TCC) and dynamic relay characteristics. The coordination of voltage restrained time over current relays with directional overcurrent 67 is usually based on static characteristics in which the time-current plots assume constant current. This assumption greatly simplifies the coordination process but fails to account for the slow-down effect due to the decrement in generator fault currents. Voltage restrained over current can be practically coordinated with normal overcurrent relays under simplifying assumptions. The resulting coordination plots are valid for close-in faults. Distant faults, for which the 51V is applied to provide backup protection, have significantly longer trip times than suggested by the simplified coordination method. The rapid trip time increase with increasing external impedance limits the reach of the 51V relay to a shorter distance than the limit obtained by considering the constant transient current. This fact must be taken into account when determining the zones of protection. In other words, the 51V may not provide the backup protection in the entire assumed zone of protection. Also, it was shown that field forcing extends the reach of the 51V relay. This is one of the benefits of static excitation.
10.	Page 115, 3.10.2.2.	Propose adding this recommendation to the TRD document .	Recommendation: After the overcurrent tap setting is chosen, a time delay can be chosen. The 51 V is a backup function and should not operate unless a primary relay fails. As such, the time delay chosen should provide ample margin to assure coordination with normal relaying. The delay must not exceed the generator short time thermal capability as defined by IEEE C50.13 or the transformer through fault protection curve as per IEEE C37.91 Annex A.
11.	Page 118, 3.10.4.1.1.	The TRD says that "The overcurrent pickup is usually set at 50 percent of generator full load current as determined by maximum real power out and exciter at maximum field forcing." IEEE C37.102 Annex A.2.6 says "For a three-phase fault at the output terminals of the transformer, the steady-state fault current (CT secondary) may be calculated by the following	It is recommended that the relay's current pickup setting should not exceed 80% of the minimum fault current (calculated with the manual regulator in service the generator was not loaded prior to fault).

		equivalent circuit (see Figure A.15). In order to find the lowest fault current, it is assumed that the automatic voltage regulator is off-line and the generator was not loaded prior to fault.”	
12.	Page 120, 3.10.4.2. Setting Considerations	The amount of backup protection these relays can provide for faults external to the generation station is sharply limited by network lines connected at the generating station’s transmission bus. Network lines produce two adverse effects. The more network lines that terminate at a bus, the more paths to divide the fault current and the less current available to each remote relay, including the 51 V. The near-normal generator terminal voltage defeats the advantage of the voltage-controlled and voltage-restrained relays. Under these circumstances, backup clearing of this fault is not obtainable.	Add in-feed effects to setting considerations in NERC TRD. Because of the fault detection problem inherent with a remote backup scheme, most generating stations with multiple network lines are designed with “local backup” protection in the form of breaker failure relaying. When local breaker failure is applied at a generating station’s transmission bus, the generator backup relay need only provide backup for faults within the generating station.
13.	Page 19, 3.1.1	Note that Function 21 (TRD Section 3.1.1) is another method of providing backup for system faults, and it is never appropriate to enable both Function 21 and Function 51V. This statement is not clearly stated on C37.102. Even in Annex A. both protection functions were enabled without referring to this recommendation.	Recommendation was to IEEE C37.102 paragraph 4.6 and a ballot comment to add to TRD considerations. 1- The transmission system is usually protected with phase distance (impedance) relays. Time coordination is attained between distance relays using definite time settings. The 51V functions have varying time delays based on their time versus current time to operate curves. Time coordinating a 51V and a 21 lends to longer clearing times at lower currents. The 51V functions are often used effectively on generator connected to distribution system where distribution feeders are protected with time inverse characteristic relays. For these reasons, it is recommended that an impedance function be used rather than a 51V function for generators connected to the transmission system. 2- It is never appropriate to enable both Function 21 and Function 51V. If transmission system uses both types of protections, then the backup can be chosen as the distance function).
	59GN-27TH Stator Ground Protection		
1.	Page 130, 3.12.2.	The performance of these functions, during fault conditions, must be coordinated with the	The issue of zero sequence voltage being impressed on the neutral of a high-impedance grounded machine is only a problem for

		system fault protection to assure that the overall sensitivity and timing of the relaying results in tripping of the proper system elements. Proper time delay is used such that protection does not trip due to inter-winding capacitance issues or instrument secondary grounds.	sensitive set 60Hz neutral overvoltage elements. It isn't an issue for the 3rd harmonic undervoltage element. The guidance given in the document is correct for the application of a single 60Hz neutral overvoltage element. But it should be clarified that variations on this application may preclude the need for a long time delay as described. For example, if two 59N elements are used, it is typical that one is set sensitive with a long time delay (to coordinate with system ground fault protection and backup) and the other is set less sensitive with short time delay. The point being that the NERC document could be misconstrued to require the long time delay regardless. We've set sensitive 59N elements and torque controlled them with negative sequence to avoid the problem altogether. In that case there is no coordination issue with high-side ground faults (or secondary fuses for that matter).
2.	Page 130, 3.12.3. Considerations and Issues	Under 3.12.3 it makes the statement that the 59GN is intended to detect phase-phase-ground faults.	Under 3.12.3 it makes the statement that the 59GN is intended to detect phase-phase-ground faults and that isn't the case. It is intended for single phase-ground protection, the phase differential relays are the desired protection to clear multi-phase faults. To my knowledge the 27TN element is unaffected by the issue being addressed in this document
3.	Page 131, 3.12.5. Example	Examples are not necessary for function 59GN/27TH because coordination is accomplished with time delay of 5 seconds or greater on the 59GN/27TH function.	Section 3.12.5 implies 5 seconds or greater is a good setting. I disagree and suggest NERC remove that statement. Just because the ground fault is low-current doesn't mean that iron-burning isn't occurring. The fault needs to be cleared a quickly as it can reliably be done. 5 seconds is excessively long. If the practitioner evaluates the problem from a knowledgeable position (understanding the phenomenon) they can avoid the miscoordination issue that NERC is driving at while still providing optimum protection for the machine. If they blindly apply a long time delay they are being negligent.
4.	Page 131, 3.12.7. Summary of Protection Function Data and Information Exchange Required for Coordination	Table 3 Excerpt — Provide time delay setting of the 59GN/27TH Provide worst case clearing time for Phase-to-ground or phase-to-phase-to-ground close in faults, including the breaker failure time.	I think this is a great opportunity for NERC to stress monitoring and data capture. If the utility captures a DFR shot during a close-in ground fault they can capture the zero sequence bus voltage during the fault while simultaneously capturing the generator neutral voltage. This will allow the engineers to 1) determine if the 59GN is susceptible as set and 2) calculate a worst case impressed expected neutral voltage. They can calculate this worst case expected neutral voltage because they know the worst case high-side bus zero sequence voltage from fault study, and from captured data they

			know the ratio of high-side bus zero sequence voltage to the neutral 60Hz voltage. It is a simple voltage divider circuit.
	59 Overvoltage Protection	none	
	78-Out of Step Protection		
1.	Page 132, 3.13.1	"Purpose of the Generator Function 78" The statement "Application of out of step is not normally required by the planning coordinator unless stability studies described in this section determine that the protection function is necessary for the generator"	Feedback to NERC: The tone of statement is not accurate, it implies in most cases it would not be needed. These days generally 78 function is generally needed for generators connected to all EHV systems (345 kV and above), and most 230 kV systems, and some 138 kV would need it depends also on the size of the machine. In the west coast my understanding it is mandatory for 230 kV systems. Older vintage generators (nukes in 70s, 80s) have not had it partly because all the ramifications of system disturbances were not fully understood at that time, and computing was also not so easy. Suggested wording to NERC: Application/need and setting of out of step of step relaying will need to be confirmed by stability studies
	81 O/U-Abnormal Frequency Protection		
1.	Pages 149-150, 3.14.3	TRD Section 3.14.3 states that "Details for setting the protection functions are provided in Section 4.58 and Figure 4.48 of [C37.102]." TRD Figure 3.14.2 copies C37.102 Figure 4.48. But it must be noted that, as C37.102 Section 4.5.8.1.1 clearly states, this Figure **only** applies if "*the turbine generators are designed to accommodate IEC 60034-3*", which may or may not be the case for all machines world-wide, especially those in North America. As C37.106 Section 4.2.2 states: "Some turbine generators are designed to accommodate the IEC 60034-3 frequency-voltage characteristics."	C37.102 and C37.106 clearly state that IEC 60034-3 applies only to some machines.
2.	Pages 150-151, 3.14.4	Proper coordination of turbine UF protection and system UFLS must be checked by the Planning Coordination and Generator Owner. This must include simulating performance of the turbine UF protection within the dynamic studies performed by the Planning Coordinator when they evaluate the system UFLS scheme.	C37.102 has a good example in the Appendix A.2.14.1. Still, it should be noted that a dynamic study must be done to confirm the coordination.

		It is not as simple as the coordination example provided in TRD Section 3.14.5. An actual example of such a PC evaluation of system UFLS against turbine UF protection would be helpful.	
3.	Page 151, 3.14.5.1	The TRD page 148, 3.14.2.3 notes that the coordination between turbine UF protection and system UFLS is "not a relay-to-relay coordination in the traditional sense; rather, it is coordination between the generator prime mover capabilities, the overfrequency and underfrequency protection, and the UFLS program and transmission system design."	Because of this, the coordination plot provided in TRD Figure 3.14.3 on page 152 does not guarantee adequate coordination between turbine UF protection and the system UFLS scheme. It only illustrates coordination between turbine UF limits and UF protection. No mention of the system UFLS scheme or turbine UF limits are made. To me this makes TRD Section 3.14.5.1 misleading.
	Page 155, Figure 3.15.2	Refer to Figure 3.15.2. The purpose of installing a GCB is lost when 87U as shown in the figure is installed. A GCB is installed to isolate the fault in generator zone by opening the GCB and keeping the power plant auxiliary system operating from switchyard via GSU. A fault in the generator zone will operate 87U and open the switchyard breaker. Thus the purpose of a GCB is defeated. 87U should be removed from Figure 3.15.2. Separate backup 87 device should be added to 87G and 87T.	Remove 87U from Figure 3.15.2 of TRD