

FirstEnergy appreciates the opportunity to review & comment on the September 1, 2009 (draft 6.5) technical reference document titled “*Power Plant and Transmission System Protection Coordination*”. We hope our input is useful to the System Protection and Control Subcommittee in its efforts to further improve the document.

Please contact Doug Hohlbaugh at (330) 384-4698 or Rich Maxwell at (330) 384-7989 for any questions you may have related to our questions below.

FE Comment #1

On page 3, the authors try to make a strong case for not setting every function in a digital relay. To some degree, they may overstate the case as there are desirable reasons that a function may be in use even if it is not specifically needed or required. They conclude that, "If there is no specific protection need for making a setting, that protection function should not be enabled." However, a function may be enabled even if it not needed for redundancy or simply for monitoring.

The SPCS has purposely and thoughtfully taken a strong position on this issue. While it would not seem inappropriate to add a note regarding use of additional functions for redundancy or back-up, this could lead to ambiguity that would undermine our position. For example, such a statement could be interpreted as endorsing use of a 51V relay to back-up a 21 relay. A protection function set to monitor or alarm does not present an issue as our focus is to avoid tripping the unit in an uncoordinated manner. We have added this distinction in the bolded statement, which now reads, “The application of a protective function to trip a unit should be based on a specific need to protect the turbine-generator. If that protection function is not needed, **DON’T USE IT!**”

FE Comment #2

On page 4, the 1st paragraph of section 1.5 titled “Assumed System Stressed Voltage Level” makes reference to NERC recommendation 8a and the 0.85 per-unit voltage as the reference stressed system voltage condition. The authors should consider updating this information to reference the successor NERC reliability standard [PRC-023 Transmission Relay Loadability](#) Standard which in requirement R1 requires evaluation at 0.85 per unit voltage and a power factor angle of 30 degrees. The authors should consider the need to conform this guideline to the PRC-023 standard and the inclusion of the 30 degree power factor angle requirement.

The basis for using 0.85 pu is Recommendation 8a as noted in the report. While it is true that this also is the basis for PRC-023 and the other SPCS documents, we believe it is appropriate to retain the original source in this document. The document does reference PRC-023 in Section 3.1.1.

The general context of section 1.5 of this paper is a discussion of voltage magnitude only. As such, we do not believe it is necessary to refer to a power factor angle in this section of the document. The SPCS further notes that because the subject of this document is generator protection rather than transmission line protection, coordination aspects that do require consideration of power factor should be based on the possible range of power factor associated with generator loading rather than the 30 degree angle in Recommendation 8a and PRC-023.

FE Comment #3

On page 5, the authors make the statement. "NERC Standard PRC-001 is intended to codify the coordination tenets expressed in this technical reference." Since the existing standard was written before this paper, it is not possible that the referenced standard could have envisioned all of the principles in this paper. This paper might be useful as a companion paper or technical reference to the draft PRC-001 version 2 standard. However, since the paper provides more of a high level guide on coordination issues, it would be difficult to develop measurable requirements based on this papers generic guidelines.

The SPCS agrees with this comment. The last sentence before Figure 1.2 has been revised to reflect our intent to highlight the work of the System Protection Coordination Standard Drafting Team developing version 2 of PRC-001. The sentence has been changed to "NERC Standards Development Project 2007-06 System Protection Coordination, Standard PRC-001 is intended to codify the coordination tenets expressed in this technical reference in a revision to Standard PRC-001."

FE Comment #4

In Table 2, the transmission system protection function column (2) often lists devices that are not mentioned in the discussion. For example 87B and 87T are listed in column 2 for the row for the generator protection function 21 but are not found in section 3.1.

Thank you for identifying this inconsistency. The document has been modified to include a brief discussion on coordination of directional distance relays with transformer and bus differential relays.

FE Comment #5

In Table 2, the "System Concerns" often include the statement "Settings should be used for planning and system studies". Although dynamic programs often contain some relay models, we are not certain that existing dynamic computer programs can model all of the details of certain device numbers under which this comment is listed. For example, re-set characteristics of overcurrent relays. Coordination of these types of relays may be limited until some of our tools are upgraded.

While it is true that models may not exist to explicitly model each relay type in existing programs, it is still possible to compare the results obtained from the program with relay setting information to make an assessment of the likelihood of a protection operating. When an explicit model is unavailable this work would need to be performed by the engineer outside the stability program. The SPCS has updated Table 2 to reflect this.

FE Comment #6

In Table 2 and in section 3.2, the authors seem to over stress the concerns of coordinating overexcitation (24) protection with UFLS. In Table 2, they cite the following:

- Generator V/Hz protection characteristics shall be determined and be recognized in the development of any UFLS system for all required voltage conditions (exchange information of UFLS setpoints and V/Hz setpoints between the Generator Owner and Transmission Owner).
- Regional UFLS program design must be coordinated with these settings.
- Must coordinate UFLS

In the first bullet, it should be noted that the Distribution Provider can also be the responsible entity for a UFLS program.

The SPCS notes that while the Distribution Provider can also be the entity responsible for implementing a UFLS program, the Transmission Owner or Distribution Provider does not have the primary responsibility for developing the UFLS program. The SPCS has modified the document to reflect that the coordination should occur primarily between the Generator Owner and the Planning Coordinator, who typically has responsibility for the design of the UFLS program and any studies that are necessary to verify coordination.

Also, there usually is no need to consider the coordination between V/Hz relaying and UFLS unless a credible island forms because UFLS will shed the excess load in a time frame of 6-30 cycles whereas V/Hz will operate in a 2 sec. - 2 minute time frame.

While it is generally true that there is no need to consider this coordination unless an island forms, this is precisely the condition for which the SPCS is concerned. Also note that although the UFLS relay operation occurs in a faster time frame than the V/Hz relays, the time period over which overvoltage conditions occur in an island and during which frequency recovers following UFLS operation extends well into the operating time frame for V/Hz relay operation. The SPCS has modified the document to highlight this as an additional reason that coordination is necessary.

The responsibility should fall to the Planning Coordinator to determine these credible islands within its area of responsibility. If a credible island is determined, a special assessment, which may include dynamic simulations and a mitigation plan, will likely be required. The

Transmission Owner(s), Distribution Provider(s) and Generator Owner(s) in the affected area would all need to participate in the assessment.

As noted above, the SPCS has modified the document to reflect that the coordination should occur primarily between the Generator Owner and the Planning Coordination, who typically has responsibility for the design of the UFLS program and any studies that are necessary to verify coordination.

FE Comment #7

In on page 14 in Table 3, the Planning Coordinator column discusses providing continuous I2 current from the system. In the excerpt in section 3.6.7, this same column states "None". The table on Page 14 should be revised to be the same as section 3.6.7.

Thank you for identifying this inconsistency. The SPCS has modified the document accordingly.

FE Comment #8

In section 3.2.2.3, the authors state, "Coordination between generating plant overexcitation protection and the transmission system is necessary for off-nominal frequency events during which system frequency declines low enough to initiate operation of underfrequency load shedding (UFLS) relays." Again, the coordination, if needed, is between the generator and the regional plan as a whole and should be the responsibility of the Planning Coordinator.

The SPCS agrees. The document has been modified as noted above.

The paper uses Figure 3.2.2 shown below as if this is a typical installation.

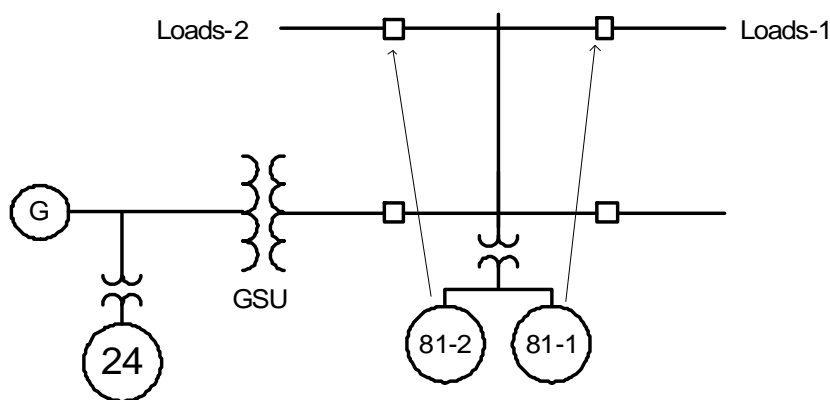


Figure 3.2.2 — Coordination between UFLS scheme and Device 24 on Generator

It should be stressed that this is not a typical installation. UFLS protection is more commonly applied at the distribution level to trip distribution feeders not transmission lines as shown here.

The SPCS has modified the figure to show a more typical installation in which the UFLS protection is supplied from a potential source on the low-side of a distribution step-down transformer. A similar change has been made to Figure 3.14.1.

As the paper states on page 37, "Coordination between the overexcitation protection and the UFLS program design can be validated only through a stability study." This is not the typical coordination of relays that one would expect. In fact, this is more of a design coordination that might be needed for a credible island situation. In the island case, it is not so much that the settings are coordinated but the UFLS plan may need to be adjusted to shed additional load or possible restore load or trip expedite tripping of capacitor banks.

The SPCS agrees that this is not the typical coordination of relays. The SPCS has modified the section noted by the commenter by inserting a sentence after the second sentence in the paragraph, "A simple relay-to-relay coordination is not possible since the protections respond to different quantities." This additional sentence adds appropriate emphasis to the next sentence, "With either approach a determination that coordination exists should be based on observing that no generators would trip by overexcitation protection."

FE Comment #9

The following from Table 3 Excerpt, column 2, page 78 is just a spelling error. The word "id" was used instead of "if."

The time-to-operate curves for system relays that respond to unbalanced system faults. This would include the 51TG id the GSU is owned by the Transmission Owner.

Thank you for identifying this error. The SPCS has modified the document accordingly.