Meeting Notes
Project 2010-13.2 Phase 2 of Relay Loadability: Generation

August 21-23, 2012

Ontario Power Generation
Niagara-On-The-Lake, Ontario

Administrative

1. **Introductions**

The meeting was brought to order by Mike Jensen, acting vice chair, at 8:00 a.m. ET on August 21, 2012. At the May 2012 meeting in Atlanta, Charles Rogers, chair, appointed Mike Jensen as vice chair to preside over the next meeting should the chair be unavailable. The vice chair recognized the in-person meeting host, Ontario Power Generation and Xiaodong Sun, for their hospitality and use of the facilities. Remote attendance was hosted via a ReadyTalk web-based conference call. Mr. Sun provided housekeeping items, logistics and a plant tour later in the meeting.

The vice chair welcomed new members Steven Hataway of Florida Power and Light and David Youngblood of Luminant Energy, a longstanding observer, as full members. A brief biography of each new member was presented to the team. The vice chair presented a brief synopsis of the goals to accomplish. Roll call and introductions were made of those in-person and attending remotely. Those in attendance were:

Name	Company	Member/ Observer	In-person (IP) or Conference Call/Web (W)		
			8/21	8/22	8/23
Mike Jensen (Acting vice chair)	Pacific Gas and Electric Company	Member	IP	IP	IP
Jeff Billo	ERCOT	Member	IP	IP	IP
S. Bryan Burch	Southern Company	Member	IP	IP	IP

Name	Company	Member/ Observer	In-person (IP) or Conference Call/Web (W)		
			8/21	8/22	8/23
Steven Hataway	Florida Power and Light Company	Member	W	W	W
Jonathan Hayes	Southwest Power Pool	Member	IP	IP	IP
Xiaodong Sun	Ontario Power Generation Inc.	Member	IP	IP	IP
Thakur Sudhir	Exelon Generation	Member	IP	IP	IP
Joe T. Uchiyama	U.S. Bureau of Reclamation	Member	IP	IP	IP
Benson Vuong	Salt River Project	Member	IP	IP	IP
David Youngblood	Luminant Energy	Member	IP	IP	IP
Daniel Woldemariam	Federal Energy Regulatory Commission	Observer	IP	IP	IP
Scott Barfield-McGinnis (Advisor)	North American Electric Reliability Corporation	Observer	IP	IP	IP
Phil Tatro (Technical Advisor)	North American Electric Reliability Corporation	Observer	IP	IP	IP

2. **Determination of Quorum**

   The rule for NERC Standard Drafting Team (SDT or team) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as ten of the eleven members were present.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**

   NERC Antitrust Compliance Guidelines and public announcement were reviewed by the advisor. There were no questions. The participants were reminded at the beginning of each day of the NERC Antitrust Guidelines.

4. **Roster Updates**

   The advisor presented the team roster and noted that Michael J. Putt and Omar Avendano who resigned have been removed from the roster. The two new members appointed to the team, Steven Hataway and David Youngblood, have been added to the team roster. The advisor asked all members to confirm their roster information was correct.

Agenda

1. **Review of Meeting Notes from Previous Meetings (Complete – no changes)**
   July 23, 2012 Conference Call

2. **Open Business from Last Meeting (Complete)**

   a. Advisor – Amended the June 29, 2012 Meeting notes to reflect that a quorum was met.

   b. Advisor – Followed up on the status of member, Mr. Avendano, and received his resignation due to employment responsibility changes.

3. **Discussion of the Results-based Standard (RBS) Draft Standard**

   The team began with a review of the informal feedback received from the North American Generator Forum and the Electric Power Supply Association, a result of the team's effort to obtain informal feedback, mitigate delays in the project, and work toward a more favorable acceptance of the standard early in its development. Both organizations had similar observations and were considered collectively.

   <u>Informal Feedback Discussions</u> – The team incorporated a number of the suggestions from the informal feedback which included removing Requirement R2 concerning implementation of the relay settings. Implementation of the setting was moved to the implementation plan. Also, the team clarified the two conditions in which facilities would become applicable; (1) upon the effective date and (2) any other change such as inclusion in the standard due to a Bulk Electric System (BES) definition change. Consideration was given the length of time for implementation of the relay settings and the team concurred to maintain the 48-month implementation period and consider industry stakeholder comments in general before decreasing or increasing the proposed

period. The team improved the clarity in 3.1 of the Applicability section to clearly denote that “load-responsive relays” are the applicable facility subject to the standard by the Generator Owner.

M1 Discussion – The phrase, “establishment of relay settings,” was removed from Measure M1 due to its ambiguity. The team agreed that it was not clear how “establishment” would be interpreted from a compliance viewpoint. The team reconsidered a double jeopardy situation between the Generator Owner failing to set its relays and having an unnecessary generation unit trip due to not having applied the appropriate setting(s). The team removed Requirement R3 to eliminate this situation, to avoid the issue of who determines the threshold for a “Transmission System event,” and because the team expects the cause of the trip would be analyzed under PRC-004 – Protection System Misoperation Identification and Correction. There was a concern about older generators which may not be capable of achieving the margin required by the various applications. The team concurred to wait and consider industry stakeholder comments before discussing exceptions to the requirements. The team made additional clarifications to Attachment 1, particularly the introductory text on how the settings are calculated and on what basis (i.e., megawatts or megavoltampere). Informal feedback suggested that auxiliary unit transformers (i.e., UAT) should not be a part of the standard. The team did not have the option of disregarding this facility because it was clearly identified within the regulatory directive applicable facilities.

The team continued with an overview by section of the entire draft standard. No changes were made to the Purpose. The Applicability section was restructured due to moving the “load-responsive” description from the “3.2 Facilities” to the “3.1 Functional Entities” section. No substantive changes were made to the Background section.

Removal of R2 – Significant changes occurred to the Requirements section. The team agreed to eliminate Requirement R2 based on the informal feedback. The advisor presented the “identify, assess, and correct” concepts. Examples were given how it would improve the standard by moving away from zero tolerance based compliance to a documented program or process of continual monitoring. Members expressed reservation about creating a standard which requires documents to be created in order to support compliance. Reservations were based on less than positive audit experiences and longstanding history of managing settings via relay settings sheets and other protection system documentation. The discussion resulted in Requirement R1 having the reference to “documenting” settings removed and the performance changed to “install” settings in accordance with the PRC-025-1 – Attachment 1: Relay Settings. Team members understood compliance would be measured by relay in a manner using evidentiary or artifact documentation, such as, relay calculations and technician installation sheets rather than developing a program to implement and verify settings.

Removal of R3 – Further discussion continued about Requirement R3 and its value to the standard. Team members agreed that Requirement R3’s double negative construction was difficult to understand. The team was concerned about the issue of how the “Transmission System event” would be determined and by whom and how reporting would occur. One member argued that the requirement had no reliability benefit, was essentially a duplication of the requirement to set relays, and would not be manageable from an enforcement standpoint. The team agreed to remove the Requirement R3 from the standard leaving only one requirement, to install settings.

Removal of M2 and M3 – Correspondingly, the Measures M2 and M3 were removed from the draft standard. Measure M1 was updated to identify dated evidence that both the settings were calculated and installed on each relay. Requirement R1 is considered a "risk-based" requirement under the NERC RBS guidelines.

Compliance Update – The Compliance section was updated to reflect the changes to the requirements and measures. One team member questioned the language in the Evidence Retention section. The advisor noted that the language was standard template language and the team is not allowed to modify the language.

Modified Attachment 1 – The PRC-025-1 – Attachment 1: Relay Settings portion of the draft standard received significant modification. Table 1 itself was restructured for readability. Team members made clarifying changes to the voltage column to improve the understanding of how to arrive at the appropriate voltage for either the calculation or simulation options. The industry standard IEEE function numbers (i.e., 21, 51, 51C, 51VR, etc.) were added to each of the relay application options for clarity.

Loading Discussion – The team had a lengthy discussion concerning the loading option A for full (100 percent) and option B for light loading (40 percent). The concern stemmed from a Generation Owner not understanding its options in choosing the full or light loading condition based on unit operation. Generator Owners might operate differently based on, for example, seasonal variability or equipment limitation; therefore, creating ambiguity in what value is appropriate for determining settings. The NERC technical advisor and a few team members were tasked to review the two options further to determine if both options A and B are necessary. The members will report when the team holds their next conference call to complete the draft standard for industry comment.

Guideline and Technical Basis – The team made improvements to the Guideline and Technical Basis by appending additional language. The Phase Distance Relay Setting Criteria section received an additional paragraph at the end to address calculating the voltage through the generator step-up unit transformer. The first criterion paragraph was modified to explain how it achieves the simplest calculation. Text specific to Requirements R2 and R3 were removed because they were unnecessary with the removal of those requirements from the draft standard.

4. **Discussion of Questions for the Comment Period**

The team reviewed the comment questions from the previous meeting. Corrections were made to reflect the changes to the standard and to ask more direct questions regarding the issues. Additional questions were added to address the standard's rationale, Attachment 1 and Table 1, and the Implementation Plan.

5. **Action Items**

   NERC Technical Advisor – Collaborate with team member Benson Vuong and others as necessary to determine if Option B (i.e., light load point – 40 percent) is necessary for reliability and the determination of relay settings and report the findings to the team.

6. **Review of the Schedule**

   The advisor noted the schedule is 11 weeks behind following the Niagara meeting. Every effort to get the project back on schedule is paramount to not having to request a second extension from FERC. The schedule will be reviewed later in the process to determine if alternative action is needed to extend the schedule.

7. **Future meeting(s)**

   There is a conference call scheduled for Thursday, August 30, 2012 to discuss findings concerning Option B (light loading).

8. **Adjourn**

   The meeting adjourned at 11:45 a.m. ET on August 23, 2012.