November 30, 2016

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: NERC Full Notice of Penalty regarding Arkansas Electric Cooperative Corporation, FERC Docket No. NP17-_-000

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby provides this Notice of Penalty[1] regarding Arkansas Electric Cooperative Corporation (AECC), NERC Registry ID# NCR01060,[2] with information and details regarding the nature and resolution of the violations[3] discussed in detail in the Settlement Agreement attached hereto (Attachment A), in accordance with the Federal Energy Regulatory Commission's (Commission or FERC) rules, regulations, and orders, as well as NERC's Rules of Procedure including Appendix 4C (NERC Compliance Monitoring and Enforcement Program (CMEP)).[4]

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* (Order No. 672), III FERC Stats. & Regs. ¶ 31,204 (2006); *Notice of New Docket Prefix "NP" for Notices of Penalty Filed by the North American Electric Reliability Corporation*, Docket No. RM05-30-000 (February 7, 2008). *See also* 18 C.F.R. Part 39 (2016). *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *reh'g denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A). *See* 18 C.F.R § 39.7(c)(2).

[2] AECC was included on the NERC Compliance Registry as a Distribution Provider, Generator Owner (GO), Generator Operator, Resource Planner, and Transmission Owner (TO) on May 31, 2007.

[3] For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, alleged, or confirmed violation.

[4] *See* 18 C.F.R § 39.7(c)(2) and 18 C.F.R § 39.7(d).

NERC is filing this Notice of Penalty with the Commission because Southwest Power Pool Regional Entity (SPP RE) and AECC have entered into a Settlement Agreement to resolve all outstanding issues arising from SPP RE's determination and findings of the violation of PRC-005-1 R2.

According to the Settlement Agreement, AECC neither admits nor denies the violation, but has agreed to the assessed penalty of seventy thousand dollars ($70,000), in addition to other remedies and actions to mitigate the instant violation and facilitate future compliance under the terms and conditions of the Settlement Agreement.

Statement of Findings Underlying the Violation

This Notice of Penalty incorporates the findings and justifications set forth in the Settlement Agreement, by and between SPP RE and AECC. The details of the findings and basis for the penalty are set forth in the Settlement Agreement and herein. This Notice of Penalty filing contains the basis for approval of the Settlement Agreement by the NERC Board of Trustees Compliance Committee (NERC BOTCC).

In accordance with Section 39.7 of the Commission's regulations, 18 C.F.R. § 39.7 (2016), NERC provides the following summary table identifying each violation of a Reliability Standard resolved by the Settlement Agreement. Further information on the subject violation is set forth in the Settlement Agreement and herein.

*SR = Self-Report / SC = Self-Certification / CA = Compliance Audit / SPC = Spot Check / CI = Compliance Investigation

NERC Violation ID	Standard	Req	VRF/ VSL	Applicable Function(s)	Discovery Method* Date	Violation Start-End Date	Risk	Penalty Amount
SPP2012010432	PRC-005-1	R2; R2.1 and R2.2	High/ Severe	GO, TO	SR 6/7/2012	6/18/2007-11/13/2015	Moderate	$70,000

<u>SPP2012010432 PRC-005-1 R2; R2.1 and R2.2 - OVERVIEW</u>
AECC initially self-reported a violation of PRC-005-1 R2 on June 7, 2012. AECC reported that it did not include certain generation protective relay tests in its master log. As a result, 71 Protection System relays exceeded the five-year maintenance and testing intervals outlined in AECC's Protection System maintenance and testing program (PSMP).[5]

[5] The Self-Report stated that there were 78 affected relays; however, SPP RE determined that seven of these relays are not subject to PRC-005-1 R2.

On November 27, 2012, SPP RE conducted a Spot Check of AECC's PSMP, identifying noncompliance with PRC-005-1 R2 for AECC's instrument transformers and DC control circuitry, as well as for other transmission and generation Protection System devices.

The root cause of this violation was AECC's misinterpretation of PRC-005-1—it considered its historical practices, primarily relying on commissioning testing, visual inspections, and breaker interruption reports, as sufficient to fulfill the requirements.

SPP RE determined that this violation posed a moderate and not serious or substantial risk to the reliability of the bulk power system (BPS). Attachment 1 to the Settlement Agreement includes the facts regarding the violation that SPP RE considered in its risk assessment.

AECC submitted its Mitigation Plan designated SPPMIT007801-1 to address the referenced violations on July 10, 2013.[6] Attachment 1 to the Settlement Agreement includes a description of the mitigation activities AECC took to address this violation. A copy of the Mitigation Plan is included as Attachment D.

SPP RE verified on December 30, 2015 that AECC had completed all mitigation activities on November 13, 2015. Attachment 1 to the Settlement Agreement provides specific information on SPP RE's verification of AECC's completion of the activities.

<u>Regional Entity's Basis for Penalty</u>

According to the Settlement Agreement, SPP RE has assessed a penalty of seventy thousand dollars ($70,000) for the referenced violation. In reaching this determination, SPP RE considered the following factors:

1. the instant violation constituted AECC's first occurrence of violation of the subject NERC Reliability Standard;
2. AECC had an internal compliance program at the time of the violation which SPP RE considered a mitigating factor, as discussed in Attachment 1 to the Settlement Agreement;
3. AECC self-reported the violation;

[6] AECC submitted a completed Mitigation Plan contemporaneously with its Self-Report on August 6, 2012. SPP RE rejected the Certification of Completion on September 11, 2012, because it did not include the full scope of the noncompliance identified during the SPP RE Spot Check. AECC revised its Mitigation Plan to include the full scope of the noncompliance discovered during the Spot Check and resubmitted on July 10, 2013.

4. AECC was cooperative throughout the compliance enforcement process;
5. there was no evidence of any attempt to conceal a violation nor evidence of intent to do so;
6. the violation posed a moderate and not a serious or substantial risk to the reliability of the BPS, as discussed in Attachment 1 to the Settlement Agreement; and
7. there were no other mitigating or aggravating factors or extenuating circumstances that would affect the assessed penalty.

After consideration of the above factors, SPP RE determined that, in this instance, the penalty amount of seventy thousand dollars ($70,000) is appropriate and bears a reasonable relation to the seriousness and duration of the violation.

Statement Describing the Assessed Penalty, Sanction or Enforcement Action Imposed[7]

Basis for Determination

Taking into consideration the Commission's direction in Order No. 693, the NERC Sanction Guidelines and the Commission's July 3, 2008, October 26, 2009 and August 27, 2010 Guidance Orders,[8] the NERC BOTCC reviewed the Settlement Agreement and supporting documentation on October 31, 2016 and approved the Settlement Agreement. In approving the Settlement Agreement, the NERC BOTCC reviewed the applicable requirements of the Commission-approved Reliability Standards and the underlying facts and circumstances of the violation at issue.

For the foregoing reasons, the NERC BOTCC approved the Settlement Agreement and believes that the assessed penalty of seventy thousand dollars ($70,000) is appropriate for the violation and circumstances at issue, and is consistent with NERC's goal to promote and ensure reliability of the BPS.

Pursuant to 18 C.F.R. § 39.7(e), the penalty will be effective upon expiration of the 30-day period following the filing of this Notice of Penalty with FERC, or, if FERC decides to review the penalty, upon final determination by FERC.

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[7] *See* 18 C.F.R. § 39.7(d)(4).

[8] *North American Electric Reliability Corporation*, "Guidance Order on Reliability Notices of Penalty," 124 FERC ¶ 61,015 (2008); *North American Electric Reliability Corporation*, "Further Guidance Order on Reliability Notices of Penalty," 129 FERC ¶ 61,069 (2009); *North American Electric Reliability Corporation*, "Notice of No Further Review and Guidance Order," 132 FERC ¶ 61,182 (2010).

Attachments to be Included as Part of this Notice of Penalty

The attachments to be included as part of this Notice of Penalty are the following documents:

a) Settlement Agreement by and between SPP RE and AECC executed September 6, 2016, included as Attachment A;

   1. Disposition of Violation, included as Attachment 1 to the Settlement Agreement;

b) AECC's Self-Report for PRC-005-1 dated June 7, 2012, included as Attachment B;

c) SPP RE's Spot Check Report dated February 1, 2013, included as Attachment C;

d) AECC's Mitigation Plan designated as SPPMIT007801-1 for PRC-005-1 submitted July 10, 2013, included as Attachment D;

e) AECC's Certification of Mitigation Plan Completion for PRC-005-1 submitted December 16, 2015, included as Attachment E; and

f) SPP RE's Verification of Mitigation Plan Completion for PRC-005-1 dated December 30, 2015, included as Attachment F.

Notices and Communications: Notices and communications with respect to this filing may be addressed to the following:

Ron Ciesiel* General Manager, Southwest Power Pool Regional Entity 201 Worthen Drive Little Rock, AR 72223 (501) 614-3265 rciesiel.re@spp.org Joe Gertsch* Manager of Enforcement, Southwest Power Pool Regional Entity 201 Worthen Drive Little Rock, AR 72223 (501) 688-1672 jgertsch.re@spp.org Lori Burrows* Vice President – General Counsel Arkansas Electric Cooperative Corporation 1 Cooperative Way Little Rock, AR 72209 (501) 570-2147 lori.burrows@aecc.com Ronnie Frizzell* Director NERC Compliance Arkansas Electric Cooperative Corporation 1 Cooperative Way Little Rock, AR 72209 (501) 570-2433 ronnie.frizzell@aecc.com	Sonia C. Mendonça* Vice President of Enforcement and Deputy General Counsel North American Electric Reliability Corporation 1325 G Street N.W. Suite 600 Washington, DC 20005 (202) 400-3000 (202) 644-8099 – facsimile sonia.mendonca@nerc.net Edwin G. Kichline* Senior Counsel and Associate Director, Enforcement North American Electric Reliability Corporation 1325 G Street N.W. Suite 600 Washington, DC 20005 (202) 400-3000 (202) 644-8099 – facsimile edwin.kichline@nerc.net Leigh Anne Faugust* Counsel, Enforcement North American Electric Reliability Corporation 1325 G Street N.W. Suite 600 Washington, DC 20005 (202) 400-3000 (202) 644-8099 – facsimile leigh.faugust@nerc.net

*Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of the Commission's rules and regulations to permit the inclusion of more than two people on the service list.	

Conclusion

NERC respectfully requests that the Commission accept this Notice of Penalty as compliant with its rules, regulations, and orders.

Respectfully submitted,

/s/ Edwin G. Kichline
Sonia C. Mendonça
Vice President of Enforcement and Deputy General Counsel
Edwin G. Kichline
Senior Counsel and Associate Director, Enforcement
Leigh Anne Faugust
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cc: Arkansas Electric Cooperative Corporation
Southwest Power Pool Regional Entity

Attachments

Attachment A

Settlement Agreement by and between SPP RE and AECC executed September 6, 2016

A-1. Disposition of Violation

[redacted]

SETTLEMENT AGREEMENT
OF
SOUTHWEST POWER POOL REGIONAL ENTITY
AND
ARKANSAS ELECTRIC COOPERATIVE CORPORATION

I. INTRODUCTION

1. The Southwest Power Pool Regional Entity ("SPP RE") and Arkansas Electric Cooperative Corporation ("AECC") (hereinafter referred to individually as "Party" and collectively as the "Parties") enter into this Settlement Agreement ("Agreement") to resolve all outstanding issues arising from the non-public determination by SPP RE, pursuant to the North American Electric Reliability Corporation ("NERC") Rules of Procedure, of the violation by AECC of the following NERC Reliability Standard ("Violation")[1].

NERC Violation Identification No.	Reliability Standard	Requirement(s)	Discovery Method	Date of Violation
SPP2012010432	PRC-005-1	R2.1, R2.2	Self Report	06/18/2007

2. AECC neither admits nor denies the Violation and has agreed to the proposed penalty of $70,000 to be assessed by SPP RE for the purpose of resolving all outstanding issues relating to the Violation pursuant to the terms and conditions of this Agreement.

II. STIPULATIONS

3. The Parties enter into this Agreement and agree to the facts stipulated herein in order to avoid uncertainty and to effectuate a complete and final resolution of the Violation. The facts stipulated herein are stipulated solely for the purpose of resolving the Violation and do not represent stipulations or admissions, by either Party, for any other purpose. In consideration of the terms set forth herein, SPP RE and AECC hereby stipulate and agree to the following:

A. BACKGROUND

4. See Section I of the Disposition Document, Attachment 1 for a description of AECC.

B. VIOLATION(S)

5. See Section II of the Disposition Document, Attachment 1 for a description of the Violation.

III. PARTIES' SEPARATE REPRESENTATIONS

[1] For purposes of this document and attachments hereto, the violation at issue is described as a "Violation," regardless of the procedural posture and whether the violation is a possible, alleged, or confirmed violation.

[redacted]

A. STATEMENT OF SPP RE

6. As a result of SPP RE's assessment of the Violation, SPP RE has established sufficient facts to reasonably support the AECC Violation.

7. SPP RE has determined that AECC has completed a Mitigation Plan for the Violation.

8. SPP RE agrees that this Agreement is in the best interest of the Parties and Bulk Power System ("BPS") reliability.

B. STATEMENT OF AECC

9. AECC neither admits nor denies that the facts set forth and agreed to by the Parties for purposes of this Agreement constitute a violation of the identified NERC Reliability Standard.

10. AECC has agreed to enter into this Agreement with SPP RE to avoid extended litigation with respect to this matter, to avoid uncertainty, and to effectuate a complete and final resolution of the Violation.

11. AECC agrees that this Agreement is in the best interest of the Parties and BPS reliability.

IV. MITIGATING ACTIONS, REMEDIES AND SANCTIONS

12. SPP RE and AECC agree that AECC has completed and SPP RE has verified completion of the mitigating actions set forth in Section IV of the Disposition Document, Attachment **1.**

13. SPP RE considered the specific facts and circumstances of the Violation, including AECC's actions in mitigation thereof, in determining a penalty satisfying the requirement in Section 215 of the Federal Power Act "that a penalty imposed under this section shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of the Registered Entity to remedy the violation in a timely manner." The factors considered by SPP RE Staff in the determination of an appropriate penalty are set forth in Section V of Disposition Document, Attachment **1.**

14. In settlement of all outstanding issues related to the Violation, the Parties agree that AECC shall pay a total penalty amount of $70,000 ("Penalty") to SPP RE via wire transfer or cashier's check payable to a SPP RE account that will be outlined in an invoice sent to AECC upon approval or acceptance of this Agreement by the NERC Board of Trustees and by the Federal Energy Regulatory Commission ("FERC" or the "Commission"), either by order or by operation of law. Payment to SPP RE shall be made within thirty (30) days after the receipt of the invoice. SPP RE shall inform NERC if the payment is not timely received.

15. Failure to make a timely Penalty payment or to comply with any other conditions of this

[redacted]

Agreement shall be deemed either a continuation of the Violation and/or additional violations and may subject AECC to new or additional enforcement, penalty or sanction actions in accordance with the NERC Rules of Procedure. AECC shall retain all rights to defend against such renewed or additional enforcement actions in accordance with the NERC Rules of Procedure.

16. If AECC fails to make the Penalty payment described above on the date agreed to by the Parties, then interest on the Penalty will begin to accrne at the rate(s) specified in the Commissions regulations at 18 C.F.R. § 35.19(a)(2)(iii) commencing on the date that payment is due. Such interest shall be payable to SPP RE in addition to the Penalty.

V. ADDITIONAL TERMS

17. The Parties agree that they enter into this Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer or promise of any kind by any member, employee, officer, director, agent, or representative of AECC or SPP RE has been made to induce the Parties to enter into this Agreement.

18. SPP RE shall report the terms of this Agreement to NERC. NERC will review the Agreement for the purpose of evaluating its consistency with other settlements entered into for similar violations or involving similar circumstances. Based on this review, NERC will either approve or reject the Agreement. If NERC rejects the Agreement, NERC will provide specific written reasons for such rejection and shall notify SPP RE and AECC of changes to the terms of the Agreement that would result in its approval, and SPP RE will attempt to negotiate a revised settlement agreement with AECC that will reflect any changes to the original Agreement. If a revised settlement cannot be reached, settlement discussions will be terminated and the enforcement process shall continue to conclusion. If NERC approves the Agreement, NERC will, upon execution by the Parties (i) file the approved Agreement with the Commission for the Commission's review and acceptance or approval by order or operation of law and (ii) may publicly post this Agreement and/or its contents.

19. This Agreement shall become effective upon the Commission's approval or acceptance of the Agreement by order or operation of law as submitted to it or as modified in a manner acceptable to the Parties.

20. AECC agrees that this Agreement, when approved or accepted by NERC and the Commission, shall represent a final settlement of all matters set forth herein and AECC waives its right to further hearings and appeal of such matters, unless and only to the extent that AECC contends that any NERC or Commission action on the Agreement contains one or more material modifications to the Agreement. SPP RE reserves all rights to initiate enforcement, penalty or sanction actions against AECC in accordance with the NERC Rules of Procedure in the event that AECC fails to comply with the terms of this Agreement. In the event AECC fails to comply with such te1ms, SPP RE may initiate enforcement, penalty, or sanction actions against AECC to the maximum extent allowed by the NERC Rules of Procedure and up to the maximum statutorily allowed penalty. Except as otherwise specified in this Agreement, AECC shall retain all rights to defend against such enforcement actions according to the NERC Rules of Procedure.

[redacted]

21. AECC consents to the use of SPP RE's determinations, findings, and conclusions set forth in this Agreement for the purpose of assessing AECC's history of violations of the NERC Reliability Standards, in accordance with the NERC Sanction Guidelines and applicable Commission orders and policy statements. Such use may be in any enforcement action or compliance proceeding undertaken by NERC and/or any Regional Entity involving the Reliability Standard described herein; provided, however, that AECC does not consent to the use of the specific acts set forth in this Agreement as the sole basis for any other action or proceeding brought by NERC and/or SPP RE, nor does AECC consent to the use of this Agreement by any other party in any other action or proceeding.

22. Each of the undersigned warrants that he or she is an authorized representative of the Party designated; is authorized to bind such Party; and, accepts the Agreement on the Party's behalf.

23. The undersigned representative of each Party affirms that he or she has read this Agreement; that all of the matters set forth in this Agreement are true and correct to the best of his or her knowledge, information and belief; and, that he or she understands that this Agreement is entered into by such Party in express reliance on those representations; provided, however, that such affirmation by each Party's representative shall not apply to the other Party's statements of position set forth in Section III of this Settlement Agreement.

24. This Agreement may be executed in one or more counterparts, each of which when so executed and delivered shall be deemed to be an original, but all of which taken together form but one and the same instrument.

25. This Agreement may be executed in duplicate, each of which so executed shall be deemed to be an original.

26. This Agreement constitutes the entire agreement between the Parties with respect to the Violation, and supersedes all prior agreements, negotiations, considerations and representations between the Parties.

27. This Agreement may be modified only by written instrument signed by a duly-authorized representative of the Parties.

Remainder of page intentionally blank.
Signatures to be affixed to the following page.

[redacted]

Agreed to and accepted:

Ron Ciesiel

Ron Ciesiel
General. Manager
Southwest Power Pool Regional Entity

9-6-16
Date

Lori L. Burrows
Vice President - General Counsel
Arkansas Electric Cooperative Cooperation

August 26, 2016
Date

[redacted]

Attachment 1

DISPOSITION OF VIOLATION[1]
Dated July 14, 2016

NERC TRACKING NO. SPP2012010432

REGISTERED ENTITY
Arkansas Electric Cooperative Corporation (AECC)

NERC REGISTRY ID
NCR01060

REGIONAL ENTITY
Southwest Power Pool Regional Entity (SPP RE)

I. REGISTRATION INFORMATION

ENTITY IS REGISTERED FOR THE FOLLOWING FUNCTIONS (BOTTOM ROW INDICATES REGISTRATION DATE):

BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
	X	X	X						X		X			
	5/31/07	5/31/07	5/31/07						5/31/07		5/31/07			

*** VIOLATION APPLIES TO SHADED FUNCTIONS**

DESCRIPTION OF THE REGISTERED ENTITY

AECC is headquartered in Little Rock, Arkansas, and is a Generation and Transmission cooperative with 17 Member Distribution Cooperatives that serve more than 62% of the geographical area of Arkansas.

AECC is a Generator Owner (GO) for seven gas-fired power plants: Bailey, Fitzhugh, McClellan, Fulton, Oswald, Magnet Cove, and Elkins, and three run-of-the-river hydroelectric plants, Ellis, Whillock, and Electric Cooperatives of Arkansas Hydropower Generating Station (HS2). All of the plants are located in Arkansas. The Fulton, Elkins, Ellis, Whillock, and HS2 plants are unmanned and are operated and maintained by personnel at other AECC power plants. Fulton is operated from Oswald, Elkins from Bailey, Ellis and Whillock from Fitzhugh, and HS2 from McClellan. AECC has 3,520 MWs of generation capacity.

AECC purchases transmission service under the SPP and Midcontinent Independent System Operator, Inc. Open Access Transmission Tariffs and has interconnections with the transmission systems of Entergy, American Electric Power/Southwestern Electric

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[1] For purposes of this document and attachments hereto, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, alleged or confirmed violation.

Power Company (AEP/SWEPCO), Southwestern Power Administration (SWPA), & OGE Energy Corp (OG&E). Where the transmission systems of these four companies are not within close proximity of AECC Member Distribution Cooperative load centers, AECC and the Member Distribution Cooperatives own radial transmission tie lines to their load centers. All of AECC's generation, the Member Distribution Cooperative load, and the transmission owned by AECC and the Member Distribution Cooperatives are within the metered boundaries of the Entergy, AEP/SWEPCO, SWPA, or OG&E transmission systems. All of AECC's interconnected transmission facilities are under the control of the Entergy, AEP/SWPECO, SWPA, or OG&E Transmission Operators (TOPs) and are only operated under TOP direction. AECC owns transmission facilities from 69 kV to 161 kV within its footprint. These facilities are substantially radial transmission facilities and only serve load. Only 20 of AECC's transmission stations are connected to the Bulk Electric System (BES).

II. VIOLATION INFORMATION

RELIABILITY STANDARD[2]	REQUIREMENT	SUB-REQUIREMENTS	VRF	VSL
PRC-005-1	**R2**	**R2.1, R2.2**	**High[3]**	**Severe**

PURPOSE OF THE RELIABILITY STANDARD AND TEXT OF THE RELIABILITY STANDARD AND REQUIREMENT(S)/SUB-REQUIREMENT(S)

The purpose statement of PRC-005-1 provides:

To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

PRC-005-1 R2 provides:

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

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[2] SPP RE determined that because the Violation began on 6/18/07 and continued until 11/13/15, the noncompliance is applicable to PRC-005-1 (6/18/07 – 9/25/11), PRC-005-1a (9/26/11 – 3/13/12), PRC-005-1b (3/14/12 – 11/24/13), PRC-005-2 (4/1/15 – 5/28/15), PRC-005-1.1b (3/25/13), and PRC-005-2(i) (5/29/2015).

[3] PRC-005-1 R2 has a "Lower" Violation Risk Factor (VRF); PRC-005-1 R2.1 has a "High" VRF. During a final review of the standards subsequent to the March 23, 2007, filing of the Version 1 VRFs, NERC identified that some standards requirements were missing VRFs; one of these included PRC-005-1 R2.1. On May 4, 2007, NERC assigned PRC-005 R2.1 a "High" VRF. In the Commission's June 26, 2007 Order on Violation Risk Factors, the Commission approved the PRC-005-1 R2.1 "High" VRF as filed. Therefore, the "High" VRF was in effect from June 26, 2007. In the context of this matter, SPP RE determined that for the violation related to R2.1, a "High" VRF is appropriate.

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

VIOLATION DESCRIPTION

On June 7, 2012, AECC submitted a Self-Report stating that, as a GO and TO, it was in violation of PRC-005-1 R2.1. During a routine review of its relay testing records and Master Relay Maintenance Log (Master Log) conducted on May 1, 2012, AECC discovered that the HS2 generation protective relay tests had not been included on its Master Log. As a result, 71 Protection System relays,[4] 57 of which were directly related to HS2 and 14 related to the HS2 transmission interconnection, exceeded the five-year maintenance and testing intervals outlined in AECC's Protection System maintenance and testing program (PSMP).

On November 27, 2012, SPP RE conducted a Spot Check of AECC's PSMP, identifying possible violations of PRC-005-1 R1 and R2.[5] The Spot Check Team identified possible violations of R2 for AECC's instrument transformers and DC control circuitry. Additionally, the Spot Check Team identified possible violations of R2 related to other AECC transmission and generation Protection System devices.

Background

The Spot Check Team reviewed AECC's PSMP documentation, which consisted primarily of the *AECC Transmission & Generation Protection System Maintenance & Testing Program (V1.0)*, dated February 5, 2008. Therein, AECC identified maintenance and testing intervals of: five (5) years for electro-mechanical protective relays; ten (10) years for microprocessor based protective relays; five (5) years for non-microprocessor based associated communication systems; ten (10) years for microprocessor based associated communication systems; three (3) years for station batteries; and a monthly battery inspection. In its PSMP document, AECC indicated the bases for the intervals for these Protection System devices were AECC's historical practices and manufacturers' guidelines. Although AECC's PSMP documentation included DC control circuitry and instrument transformers, AECC did not establish a maintenance and testing interval for these Protection System components. Instead, AECC indicated that these Protection System components would be tested according to "common industry practices or manufacturer's guidelines." For instrument transformers, AECC stated "[w]hen there is evidence, or reasonable suspicion, of a Protection System voltage or current sensing device misoperation, the equipment in question will be promptly tested and remedial action taken." A similar statement was included for all Protection System devices, including DC control circuitry.

[4] The Self-Report stated that there were 78 affected relays; however, SPP RE determined that 7 of these relays are not subject to PRC-005-1 R2.
[5] NERC posted AECC's noncompliance with PRC-005-1 R1 as an FFT ion June 30, 2015.

Because PRC-005-1 requires that maintenance and testing intervals be established for Protection System devices, the Spot Check Team found AECC in violation of PRC-005-1 R1 for failing to establish maintenance and testing intervals for its instrument transformers and DC control circuitry. In response to the Spot Check Teams R1 findings related to DC control circuitry, AECC stated:

> AECC has followed its maintenance and testing program by conducting or verifying the test results of all new or modified DC control circuitry in the Protection System prior to placing the equipment into service.
>
> After being commissioned into service, AECC verifies the integrity of its DC system components by performing regular visual inspections to ensure that various DC components are functional such as breaker status lamps, trip coils, and the presence of DC voltage. These substation inspection reports also record relay targets and breaker operations indicating that the main trip paths are functional.
>
> Circuit breaker operations which clear faults are recorded and serve as evidence that the DC control circuitry functioned properly. Full functional testing of DC circuit components is done if there is evidence, or reasonable suspicion, that a problem exists. Any defective component found during testing is repaired or replaced promptly.
>
> The basis for this testing philosophy stems from 50+ years of AECC experience in understanding the function and operation of DC control circuitry. A successful recorded circuit breaker operation initiated by a protective relay is clear evidence of a proper functioning DC tripping path. AECC views a comprehensive test of DC circuitry as one that includes the actual operation or a series of validated performance measurements of all components in the DC circuitry (i.e. relays, wiring, auxiliary contacts, coils, etc.). AECC also considers a control switch operation of a circuit breaker as a test to determine the level of confidence in the functionality of a DC circuit. A high confidence level is developed upon a successful control switch operation due in fact that the control switch contact is in parallel with relay tripping contacts and thus verifies a very large segment of the tripping path. The protective relay wiring and relay cases are fixed and do not change unless a modification has been to the system or individual relay panel. This would minimize the need for testing of these components on a prescribed maintenance interval.

AECC provided the Spot Check Team a similar statement related to the requirement to establish intervals for the maintenance and testing of its instrument transformers. AECC stated:

> AECC followed its maintenance and testing program by conducting or verifying the test results of all new or modified voltage and current sensing devices in the Protection System prior to placing the equipment into service. Tests are conducted according to common industry practices or manufacturer's guidelines (see insert below).
>
> Upon being commissioned into service, voltage and current sensing devices are not regularly scheduled for any further testing unless there is evidence, or reasonable suspicion, that a misoperation has occurred. The basis for this testing philosophy stems from 50+ years of AECC experience in understanding the function and operation of voltage and current sensing devices. The instrument transformer devices are relatively simple consisting of an iron core and copper windings. The accuracy and repeatability of these devices remains extremely high throughout its lifecycle. Sudden output failures are very uncommon and there is no evidence in AECC's records indicating that a voltage or current sensing device was ever a culprit in a reportable AECC bulk electric system misoperation event.
>
> For instrument transformers that are viewable, visual inspections are routinely performed and in the unlikely event a voltage or current sensing device was found to be inoperative or damaged, it would be repaired or replaced promptly.
>
> AECC is confident that the voltage and sensing devices within its transmission and generation system are in good working order and are strong reliability components in the overall Protection System.

Accompanying the above statement regarding instrument transformers AECC provided the Spot Check Team with an excerpt from an *ABB Kuhlman Oil-filled Instruction Manual – 15kV to 161kV Ratings* for instrument transformers. Therein, the Maintenance section states: "General recommendations – Other than routine conventional maintenance, ABB Kuhlman instrument transformers only require periodic inspections and check of the oil level."

Notwithstanding the positions and support presented by AECC, the Spot Check Team was not persuaded that AECC's approach to maintaining and testing its instrument transformers and DC control circuity met the requirements of PRC-005.

Transmission

The Spot Check Team sampled 29 of 139 AECC Protection System relays and their associated devices, covering 15 of 20 BES transmission facilities. The Spot Check Team compared the maintenance and testing reports provided by AECC with the intervals and the maintenance and testing procedures established in AECC's PSMP.

[redacted]

Instrument Transformers

To evidence the maintenance and testing of its instruments transformers, AECC relied principally on its transmission facility commissioning test records. Other than visual inspections, AECC was unable to provide the Spot Check Team with any evidence of post commissioning maintenance and testing of its instrument transformers. Accordingly, some of AECC's instrument transformers had not been maintained or tested since 1964. The Spot Check Team determined that AECC was not maintaining and testing its Protection System instrument transformers.

DC Control Circuitry

To evidence the maintenance and testing of DC control circuitry AECC relied on commissioning tests and breaker interruption reports. AECC was unable to provide interruption reports for the Fitzhugh Switch Station – Igo and Fulton CT1 – Couch transmission circuit breakers. No commissioning test was provided for the DC control circuity associated with the Fitzhugh Switch Station – Igo circuit breaker. The commissioning tests provided by AECC for the Fulton CT1 – Couch circuit breaker indicated that the DC control circuitry for the associated relays was last tested in 2000. The Spot Check Team determined that the evidence provided by AECC was incomplete and did not establish that AECC was maintaining its DC control circuity in accordance with its PSMP. Moreover, the method utilized by AECC to tests its DC control circuitry did not test the continuity of every path associated with a DC control circuit.

Battery Banks

The sample of the 15 transmission facilities examined by the Spot Check Team included eight battery banks. The Spot Check Team determined that the maintenance and testing of all eight battery banks were incomplete and/or had questionable data with no explanation and/or corrective actions. Monthly battery inspection data was missing for various months during the audit period for all eight battery banks sampled. For example, no monthly battery inspection data was provided for 2008 and 2009 at the Farmington station, 2008 and 2009 at the Fitzhugh station, 2009 at the Fulton station, 2008 and 2009 at the Helena station, 2008 – 2011 at the HS2 hydro switch station and 2008 and 2009 at the Whillock hydro switch station. Several deficiencies were identified in the maintenance and testing reports that were provided by AECC with no explanation or documentation that corrective action was taken. For example, the three year maintenance report for the (B) battery bank at the McClellan station states: "Test battery bank, lots of corrosion present on terminals. Terminals need to be clean with new straps, nuts, and bolts. Batteries need to be wiped down and clean. Cells or batteries 57, 58, 59 are parallel within a series set of batteries. Don't know why. Bank (B) is reading higher voltage per (illegible). Maybe to compensate for cells (57-59) which are not being charged. Need to be put on equalize." The Spot Check Team asked AECC about the corrective action to address the McClellan battery issues. AECC responded, "[t]he battery deficiencies that were noted in the inspection dated 1/12/11 will be corrected in March 2013 during a generating plant shutdown period. It is of the opinion of AECC operations personnel that the battery bank in its present condition is capable of normal performance until the repairs are made."

Generation

The Spot Check Team sampled 29 of AECC's 336 Protection System relays and their associated devices, covering 18 of AECC's 26 generation facilities. The Spot Check Team compared the maintenance and testing reports provided by AECC with the intervals and the maintenance and testing procedures in AECC's PSMP.

Voltage and Current Sensing Devices

To evidence the maintenance and testing of its instruments transformers, AECC relied principally on its generation facility commissioning test records. AECC was unable to provide commissioning tests or other test data to support the maintenance and testing of instrument transformers at the Bailey and McClellan generating stations. For the Fitzhugh Unit 2, Whillock Unit 1 and Fulton CT1 generators, the test reports were not filled out completely. Other than visual inspections, AECC was unable to provide the Spot Check Team with any evidence of post commissioning maintenance and testing of its instrument transformers. AECC's Protection System maintenance and testing records indicated that some of its instrument transformers had not been maintained or tested since 1964. The Spot Check Team determined that AECC was not maintaining and testing its instrument transformers.

DC Control Circuitry

To evidence the maintenance and testing of DC control circuitry, AECC relied on commissioning tests and breaker interruption reports. AECC could not provide interruption reports for the HS2 ECA transmission line circuit breaker, HS2 ECA Unit 1 and Fulton CT1. No commissioning tests were provided for the DC control circuity associated with the Bailey, Fitzhugh Unit 2, McClellan, Whillock Unit 1 and Fulton CT1 generators. The Spot Check Team determined that the evidence provided by AECC was incomplete and did not establish that AECC was maintaining its DC control circuity in accordance with its PSMP. Moreover, the method utilized by AECC to test its DC control circuitry did not test the continuity of every path associated with a DC control circuit.

Battery Banks

The sample of AECC generation facilities examined by the Spot Check Team included seven battery banks. SPP RE determined that the maintenance and testing of all seven battery banks was incomplete and/or had questionable data with no explanation and/or corrective actions. For example, AECC did not provide documentation of the monthly battery inspections for HS2 Unit 1 and Unit 2. At other locations, battery inspections for various months were missing. For example, the 2009 monthly battery inspection data provided by AECC for the Bailey station was missing every month except March, April and May. One or more monthly battery inspections were missing at the Bailey station for 2010, 2011 and 2012. At the Oswald Generating Station, the test data for cell voltage for the 2010, 3 year battery bank test indicated that all cells were below the minimum of 1.43 volts. No corrective action was indicated on the test report.

As to the failure to maintain and test its instrument transformers and DC control circuitry, the root cause of this noncompliance was AECC's misinterpretation of the PRC-005-1 Standard. AECC considered its historical practices as sufficient grounds to rely on commissioning tests and breaker interruption reports to fulfill the requirements of PRC-005. As to the noncompliance associated with the missing and incomplete testing of Protection System equipment, the root cause was lack of management oversight and controls to ensure the testing was performed.

RELIABILITY IMPACT STATEMENT- POTENTIAL AND ACTUAL

It is SPP RE determination that AECC's violation of PRC-005-1 R2 posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). By failing to maintain and test its Protection System devices AECC increased the risk of Protection System misoperations on its electrical system. Such misoperations can result in damage to system equipment, the unnecessary loss system generation and load, and cascading system outages. As to the failure to test the HS2 relays within the five-year interval in its PSMP, the risk to the BPS is minimal. HS2 is a 102.6 MW run of the river hydroelectric generating facility that was commissioned in 1999. Because it is a run of the river generating facility, it is only capable of generating when sufficient flow and head are available on the Arkansas River. Accordingly, HS2 is not relied upon by system operators to provide generation or system voltage support.

As to AECC's failure to maintain and test its DC control circuitry, instrument transformers and batteries, it is SPP RE's determination the risk to the BPS is moderate. The risk to the BPS was mitigated because:

1) AECC was testing its Protection System relays. A review of the AECC's relay test records by the Spot Check Team indicated that all of the sampled Protection System relays were tested within the intervals prescribed in AECC's PSMP. By testing its relays, AECC confirmed the functionality of its relays and the availability of relay inputs, e.g. DC voltage, potential and current inputs;

2) AECC performed a review of protective relay operations following an event. This review verified correct operation or identified corrective action to be taken if a misoperation had occurred;

3) AECC's instrument transformers utilized for metering and SCADA provide indication of instrument transformer problems; and,

4) There were no known system events that were attributable to AECC's failure to maintain and test its Protection System devices.

[redacted]

Attachment 1

IS THERE A SETTLEMENT AGREEMENT	**YES**	☒	**NO**	☐

WITH RESPECT TO THE VIOLATION(S), REGISTERED ENTITY

NEITHER ADMITS NOR DENIES IT (SETTLEMENT ONLY)	**YES**	☒
ADMITS TO IT	**YES**	☐
DOES NOT CONTEST IT (INCLUDING WITHIN 30 DAYS)	**YES**	☐

WITH RESPECT TO THE ASSESSED PENALTY OR SANCTION, REGISTERED ENTITY

ACCEPTS IT/ DOES NOT CONTEST IT	**YES**	☒

III. DISCOVERY INFORMATION

METHOD OF DISCOVERY

SELF-REPORT	☒
SELF-CERTIFICATION	☐
COMPLIANCE AUDIT	☐
COMPLIANCE VIOLATION INVESTIGATION	☐
SPOT CHECK	☒
COMPLAINT	☐
PERIODIC DATA SUBMITTAL	☐
EXCEPTION REPORTING	☐

DURATION DATE(S) The violation began on 06/18/07, when PRC-005-1 became mandatory and enforceable and ended on 11/13/15, when AECC completed its Mitigation Plan.

DATE DISCOVERED BY OR REPORTED TO REGIONAL ENTITY

06/07/2012 (Self-Report); 11/27/2012 (Spot-Check)

IS THE VIOLATION STILL OCCURRING	**YES**	☐	**NO**	☒
IF YES, EXPLAIN				
REMEDIAL ACTION DIRECTIVE ISSUED	**YES**	☐	**NO**	☒
PRE TO POST JUNE 18, 2007 VIOLATION	**YES**	☐	**NO**	☒

IV. MITIGATION INFORMATION

FOR FINAL ACCEPTED MITIGATION PLAN:

MITIGATION PLAN NO. SPPMIT007801-1

[redacted]

Attachment 1

DATE SUBMITTED TO REGIONAL ENTITY	07/10/13
DATE ACCEPTED BY REGIONAL ENTITY	07/11/13
DATE APPROVED BY NERC	07/22/13
DATE PROVIDED TO FERC	07/22/13

IDENTIFY AND EXPLAIN ALL PRIOR VERSIONS THAT WERE ACCEPTED OR REJECTED, IF APPLICABLE

AECC submitted a completed Mitigation Plan contemporaneously with its Self-Report on August 6, 2012. The Certification of Completion was rejected on September 11, 2012, because it did not include the noncompliance identified during the SPP RE Spot Check. AECC's Mitigation Plan was revised to include the noncompliance discovered during the Spot Check and resubmitted on July 10, 2013.

MITIGATION PLAN COMPLETED **YES** ☒ **NO** ☐

EXPECTED COMPLETION DATE	07/01/16
EXTENSIONS GRANTED	N/A
ACTUAL COMPLETION DATE	11/13/15
DATE OF CERTIFICATION LETTER	12/16/15
CERTIFIED COMPLETE BY REGISTERED ENTITY AS OF	11/13/15
DATE OF VERIFICATION LETTER	12/30/15
VERIFIED COMPLETE BY REGIONAL ENTITY AS OF	11/13/15

ACTIONS TAKEN TO MITIGATE THE ISSUE AND PREVENT RECURRENCE

To mitigate this violation, AECC:

1) analyzed its records and identified the voltage and current sensing devices and DC control circuitry that needed to be tested;
2) tested all identified voltage and current sensing devices and DC control circuitry from step 1 and ensured the devices were functioning properly;
3) implemented work process improvements to ensure documents and records are being properly logged;
4) implemented a check out system for the relay test files to provide better tracking of the records;
5) implemented a process to reconcile the Master Log to ensure that all relays for which AECC is responsible are included in the relay maintenance and testing program; and
6) implemented a monthly review to ensure that maintenance and testing is being properly logged and the schedule for maintenance and testing is on track and

being followed in accordance with the PSMP maintenance and testing intervals.[6]

LIST OF EVIDENCE REVIEWED BY REGIONAL ENTITY TO EVALUATE COMPLETION OF MITIGATION PLAN (FOR CASES IN WHICH MITIGATION IS NOT YET COMPLETED, LIST EVIDENCE REVIEWED FOR COMPLETED MILESTONES)[7]

AECC Potential Violation Self Report 6-7-12.pdf
AECC PRC-005 BES Impact Worksheet.xls
PRC-005-1 R2 Analysis.pdf
PRC-005 R2 Mitigation Plan April 2014 Evidence - 1 of 2.pdf
PRC-005 R2 Mitigation Plan April 2014 Evidence - 2 of 2.pdf
PRC-005 Mitigation Plan Evidence 2014 Q3.pdf
PRC-005-1 R2 Mitigation Plan Evidence Email 12-18-14.pdf
PRC-005-1 R2 Mitigation Plan Evidence for Q3 2015.pdf
PRC-005-1 R2 Mitigation Plan Evidence for Q4 2015.pdf
PRC-005-1 R2 Mitigation Plan Evidence.pdf
PRC-005-1 R2 Mitigation Plan Milestone.pdf
AECC PRC-005 R2 MP Milestone 7-1-14 (1 of 3)
  Dell 500 SS Control Circuitry.pdf
  Dell 500 SS Sensing Devices.pdf
  Oswald Plant - Unit 5 Control Circuitry.pdf
  Oswald Plant - Unit 5 Sensing Device.pdf
  Oswald Plant - Unit 6 Control Circuitry.pdf
  Oswald Plant - Unit 6 Sensing Device.pdf
  Oswald Plant - Unit 7 Control Circuitry.pdf
  Oswald Plant - Unit 7 Sensing Device.pdf
  PRC-005-1 R2 Mitigation Plan Evidence (1 of 3).pdf
AECC PRC-005 R2 MP Milestone 7-1-14 (2 of 3)
  Oswald Plant - Unit 7 Control Circuitry.pdf
  Oswald Plant - Unit 7 Sensing Device.pdf
  Oswald Plant Sub - GSU 1 Control Circuitry.pdf
  Oswald Plant Sub - GSU 1 Sensing Device.pdf
  Oswald Plant Sub - GSU 2 Control Circuitry.pdf
  Oswald Plant Sub - GSU 2 Sensing Device.pdf
  Oswald Plant Sub - GSU 3 Control Circuitry.pdf
  Oswald Plant Sub - GSU 3 Sensing Device.pdf
  Oswald Plant Unit 8 Control Circuitry.pdf

[6] In April of 2014, SPP RE conducted an Operations and Maintenance Compliance Audit of AECC. SPP RE relied on evidence submitted by AECC during the Compliance Audit to substantiate performance of the maintenance and testing of Protection System batteries.

Oswald Plant Unit 8 Sensing Device.pdf
Oswald Plant Unit 9 Control Circuitry.pdf
Oswald Plant Unit 9 Sensing Device.pdf
PRC-005-1 R2 Mitigation Plan Evidence (2 of 3).pdf
AECC PRC-005 R2 MP Milestone 7-1-14 (3 of 3)
Fulton 115kv SS - GSU Breaker Sensing Device update.pdf
Oswald Plant - Unit 3 Breaker 52-3 CT Trouble Report.pdf
Oswald Plant - Unit 3 Sensing Device update.pdf
PRC-005-1 R2 Mitigation Plan Evidence (3 of 3).pdf
2015 Q1 Mitigation Plan Evidence
Bailey 161kV Switching Station - Moses Line
Bailey 161kV Switching Station - Moses Line Control Circuitry.pdf
Bailey 161kV Switching Station - Moses Line Sensing Devices.pdf
Bailey 161kV Switching Station - Newport Line
Bailey 161kV Switching Station - Newport Line Sensing Devices.pdf
Bailey 161kV Switching Station - Newport Line Control Circuitry.pdf
Dell 161kV Switching Station
Dell 161kV Switching Station - Sensing Devices.pdf
Dell 161kV Switching Station - Control Circuitry.pdf
HS9 Whillock Plant 3 - Unit 3 and GSU 3
HS9 - Plant 3 Unit 3 and GSU3 Sensing Devices.pdf
HS9 - Plant 3 Unit 3 and GSU3 Control Circuitry.pdf
McClellan 115kV Switching Station - Camden Maguire Line
McClellan 115kV Switching Station - Camden Maguire Line Sensing Devices.pdf
McClellan 115kV Switching Station - Camden Maguire Line Control Circuitry.pdf
McClellan 115kV Switching Station - Camden North Line
McClellan 115kV Switching Station - Camden North Sensing Devices.pdf
McClellan 115kV Switching Station - Camden North Line Control Circuitry.pdf
2015 Q2 Mitigation Plan Evidence
HS9 Whillock Plant 1 - Unit 1 and GSU 1
HS9 - Plant Unit 1 and GSU1 Sensing Devices.pdf
HS9 - Plant Unit 1 and GSU 1 Control Circuitry.pdf
HS9 Whillock Plant 2 - Unit 2 and GSU 2
HS9 - Plant 2 Unit 2 and GSU 2 Control Circuitry.pdf
HS9 - Plant 2 Unit 2 and GSU 2 Sensing Devices.pdf
Bailey 161kV SS - Main Bus
Bailey 161kV Switching Station - Main Bus Sensing Devices.pdf
Bailey 161kV Switching Station - Main Bus Control Circuitry.pdf
Bailey Plant - Unit 1 and GSU 1
Bailey Plant - Unit 1 and GSU 1 Sensing Devices.pdf

[redacted]

Bailey Plant - Unit 1 and GSU 1 Control Circuitry.pdf
Blytheville North Control Circuitry.pdf
Blytheville North Voltage and Current Sensing Devices.pdf
East Centerton
East Centerton Control Circuitry.pdf
East Centerton Sensing Devices.pdf
HS2 ECA 115kV SS - 115kV Main Line
HS2 - SS Main Line Sensing Devices.pdf
HS2 - SS Main Line Control Circuitry.pdf
HS2 ECA 115kV SS - Dumas Line
HS2 - SS Dumas Line Sensing Devices.pdf
HS2 - SS Dumas Line Control Circuitry.pdf
HS2 ECA 115kV SS - Main Bus
HS2 - SS Main Bus Sensing Devices.pdf
HS2 - SS Main Bus Control Circuitry.pdf
Fitzhugh Plant and Switching Station BES Elements
Fitzhugh 161kV Switching Station - 161kV Main Bus
Fitzhugh SS - 161kV Main Bus Sensing Devices.pdf
Fitzhugh SS - 161kV Main Bus Control Circuitry.pdf
Fitzhugh 161kV Switching Station - Helburg Line
Fitzhugh SS - Helburg Line Sensing Devices.pdf
Fitzhugh SS - Helburg Line Control Circuitry.pdf
Fitzhugh 161kV Switching Station - Igo Line
Fitzhugh SS - Igo Line Sensing Devices.pdf
Fitzhugh SS - Igo Line Control Circuitry.pdf
Fitzhugh 161kV Switching Station - Ozark Dam Line
Fitzhugh SS - Ozark Dam Line Sensing Devices.pdf
Fitzhugh SS - Ozark Dam Line Control Circuitry.pdf
Fitzhugh Plant (GT) - GT & GSU 2
Fitzhugh Plant - GT & GSU 2 Control Circuitry.pdf
Fitzhugh Plant - GT & GSU 2 Sensing Devices.pdf
Fitzhugh Plant (ST) - ST & GSU 1
Fitzhugh Plant - ST & GSU1 Sensing Devices .pdf
Fitzhugh Plant - ST & GSU1 Control Circuitry.pdf
Fulton
Fulton CT1 Control Circuitry.pdf
Fulton CT1 Sensing Devices.pdf
Fulton SS Couch Control Circuity.pdf
Fulton SS Couch Sensing Devices.pdf
Fulton SS Main Bus Control Circuitry.pdf
Fulton SS Main Bus Sensing Devices.pdf
Fulton SS Okay Control Circuity.pdf
Fulton SS Okay Sensing Devices.pdf

[redacted]

HS2 ECA 115kV SS - 115kV Main Line
  HS2 - SS Main Line Sensing Devices.pdf
  HS2 - SS Main Line Control Circuitry.pdf
HS2 ECA 115kV SS - Dumas Line
  HS2 - SS Dumas Line Sensing Devices.pdf
  HS2 - SS Dumas Line Control Circuitry.pdf
HS2 ECA 115kV SS - Main Bus
  HS2 - SS Main Bus Sensing Devices.pdf
  HS2 - SS Main Bus Control Circuitry.pdf
HS2 ECA Plant 1 - Unit 1 & GSU 1
  HS2 - Plant Unit 1 and GSU 1 Sensing Devices.pdf
  HS2 - Plant Unit 1 and GSU 1 Control Circuitry.pdf
HS2 ECA Plant 2 - Unit 2 & GSU 2
  HS2 - Plant Unit 2 and GSU 2 Control Circuitry.pdf
  HS2 - Plant Unit 2 and GSU 2 Sensing Devices.pdf
HS2 ECA Plant 3 - Unit 3 & GSU 3
  HS2 - Plant Unit 3 and GSU 3 Sensing Devices.pdf
  HS2 - Plant Unit 3 and GSU 3 Control Circuitry.pdf
HS2 Plant Relay Test List.xls
HS2_File_1[1].pdf
HS2_File_2[1].pdf
HS2_File_3[1].pdf
HS2_File_4[1].pdf
HS2_File_5[1].pdf
HS2_File_6[1].pdf
HS2_File_7[1].pdf
HS2_File_8[1].pdf
HS2_File_9[1].pdf
HS2_File_10[2].pdf
HS2_File_11[1].pdf
HS2 File 12.pdf
HS9 SS Main Bus Sensing Devices.pdf
HS9 SS Main Bus Control Circuitry.pdf
HS9 SS Morrilton East Line Control Circuitry.pdf
HS9 SS Morrilton East Line Voltage and Current Sensing Devices.pdf
HS9 SS Pinnacle Line Control Circuitry.pdf
HS9 SS Pinnacle Line Voltage and Current Sensing Devices.pdf
Helena Industrial - Gillette Line
  Helena Industrial - Gillette Line Control Circuitry.pdf
  Helena Industrial - Gillette Line Sensing Devices.pdf
Helena Industrial - Ritchie Line
  Helena Industrial - Ritchie Line Control Circuitry.pdf
  Helena Industrial - Ritchie Line Sensing Devices.pdf

[redacted]

Magnet Cove 500kV SS Main Bus Control Circuitry.pdf
Magnet Cove 500kV SS Main Bus Sensing Devices.pdf
Magnet Cove Plant 1 CT1 Control Circuitry.pdf
Magnet Cove Plant 1 CT1 Sensing Devices.pdf
Magnet Cove Plant 2 ST1 Control Circuitry.pdf
Magnet Cove Plant 2 ST1 Sensing Devices.pdf
Magnet Cove Plant 3 CT2 Control Circuitry.pdf
Magnet Cove Plant 3 CT2 Sensing Devices.pdf
McClellan 115kV Switching Station - Main Bus Control Circuitry.pdf
McClellan 115kV Switching Station - Main Bus Sensing Devices.pdf
McClellan Plant - Unit 1 and GSU 1 Control Circuitry.pdf
McClellan Plant - Unit 1 and GSU 1 Sensing Devices.pdf
Osage Creek 161kV Main Bus Control Circuitry.pdf
Osage Creek 161kV Main Bus Sensing Devices.pdf
Osage Creek 161kV Transfer Tie Breaker Control Circuitry.pdf
Osage Creek 161kV Transfer Tie Breaker Sensing Devices.pdf
Oswald
- Oswald Unit 1 Control Circuitry.pdf
- Oswald Unit 1 Sensing Devices.pdf
- Oswald Unit 2 Control Circuitry.pdf
- Oswald Unit 2 Sensing Devices.pdf
- Oswald Unit 3 Control Circuitry.pdf
- Oswald Unit 3 Sensing Devices.pdf
- Oswald Unit 4 Control Circuitry.pdf
- Oswald Unit 4 Sensing Devices.pdf

AECC Certificate of Completion.pdf
copy_master_log-08202012130603[2].pdf
relay_master_log_procedure-08102012145733[1].pdf
relay_test_file_checkout_procedure-08202012140201[1].pdf
relay_test_master_log_updated_copy-08202012140625[1].pdf
Scan_of_relay_file_checkout_sheet_DOC080312-08032012104306[1].pdf
PROTSYS Magnet Cove Relays Portfolio (PRC-005-R2).pdf
PROTSYS Magnet Cove Sensing Devices Portfolio (PRC-005-R2).pdf
PROTSYS Dell 500 Battery and Charger Portfolio (PRC-005-R2).pdf
PROTSYS Dell 500 Communication Equipment Portfolio (PRC-005-R2).pdf
PROTSYS Dell 500 Control Circuits Portfolio (PRC-005-R2).pdf
PROTSYS Dell 500 Relays Portfolio (PRC-005-R2).pdf
PROTSYS Dell 500 Sensing Devices Portfolio(PRC-005-R2).pdf
PROTSYS HS9 Sw Station Trip Paths Portfolio (PRC-005-R2).pdf
PROTSYS Magnet Cove Battery and Charger Portfolio (PRC-005-R2).pdf

PROTSYS Magnet Cove Communication Equipment Portfolio (PRC-005-2).pdf

[redacted]

PROTSYS Magnet Cove Control Circuits Portfolio (PRC-005-R2).pdf

V. PENALTY INFORMATION

TOTAL ASSESSED PENALTY OR SANCTION OF $70,000 FOR ONE VIOLATION OF THE RELIABILITY STANDARD.

(1) REGISTERED ENTITY'S COMPLIANCE HISTORY

PREVIOUSLY FILED VIOLATIONS OF ANY OF THE INSTANT RELIABILITY STANDARD(S) OR REQUIREMENT(S) THEREUNDER
YES ☐ **NO** ☒

PREVIOUSLY FILED VIOLATIONS OF OTHER RELIABILITY STANDARD(S) OR REQUIREMENTS THEREUNDER

YES ☒ **NO** ☐

LIST VIOLATIONS AND STATUS

A Find, Fix, Track and Report (FFT) informational posting addressing remediated issues for certain registered entities including AECC noncompliance with VAR-002-1 R1, VAR-002-1 R2, and R2.2, and PRC-008-0 R2, was posted on the NERC website on May 28, 2015. The 60-day review period passed on July 27, 2015.

A Find, Fix, Track and Report (FFT) informational posting addressing remediated issues for certain registered entities including AECC noncompliance with PRC-005-1 R1 and FAC-009-1 R1 was posted on the NERC website on June 30, 2015. The 60-day review period passed on August 29, 2015.

SPP RE considered AECC's compliance history and determined that it was not an aggravating factor for purposes of its penalty determination because the prior noncompliance issues involved different standards and requirements and are unrelated to the testing of Protection System devices.

ADDITIONAL COMMENTS

N/A

(2) THE DEGREE AND QUALITY OF COOPERATION BY THE REGISTERED ENTITY (IF THE RESPONSE TO FULL COOPERATION IS "NO," THE ABBREVIATED NOP FORM MAY NOT BE USED.)

FULL COOPERATION **YES** ☒ **NO** ☐
IF NO, EXPLAIN

[redacted]

(3) THE PRESENCE AND QUALITY OF THE REGISTERED ENTITY'S COMPLIANCE PROGRAM

IS THERE A DOCUMENTED COMPLIANCE PROGRAM
YES ☒ NO ☐ UNDETERMINED ☐
EXPLAIN

AECC has an overall FERC Compliance Program (Program) which was developed under AECC Board Policy CCB-ADM-010 to address AECC's obligations for meeting compliance with FERC jurisdictional requirements. Under the Program, the NERC Reliability Standards are addressed by two plans, AECC's NERC 693 Reliability Standards Compliance Plan (693 Plan) and the AECC CIP Compliance Plan (CIP Plan). The 693 Plan addresses compliance with the NERC 693 (O&P) Standards, SPP Regional Reliability Standards, and the NERC CIP-001 Standard. The CIP Plan addresses compliance with the remaining CIP Reliability Standards. Both plans are applicable to AECC and AECC's 17 Member Distribution Cooperatives. Responsibilities for the NERC Reliability Standards applicable to AECC's Member Distribution Cooperatives have been delegated to AECC through a Delegation Agreement.

AECC's 693 Plan encompasses its compliance organization, awareness, assignments and responsibilities, compliance administration, compliance reporting, reporting potential noncompliance, training and education, internal reviews and audits, internal controls, the management of NERC Alerts, and data reporting to NERC for such things as TADS, GADS, and DADS.

AECC's Compliance Committee is composed of four vice presidents, which report directly to the CEO. The Compliance Committee is chaired by AECC's Executive Vice President and General Counsel who supervises the Legal Division. The Compliance Committee has assigned responsibility for the 693 Plan and CIP Plan to Compliance Managers. Each Compliance Manager is responsible for administering their respective Plans. Compliance responsibility for each Standard and/or requirement is assigned to the specific department(s) responsible for conducting the work associated with the Standard or requirement. Department heads are responsible for assigning specific compliance related tasks to department members and identifying subject matter experts (SMEs). All employees responsible for compliance report directly or through their chain of command to one of the Vice Presidents on the Compliance Committee.

For the CIP Standards, AECC has assigned the Vice President and CIO as the CIP Senior Manager with responsibility and authority for leading the implementation of the CIP Standards. The CIP Compliance Manager has responsibility for managing the implementation of the CIP Standards. All internal and external compliance reporting for the CIP Standards occurs through the same process as described in the 693 Plan.

AECC also established a Compliance Department within the Legal Division after this issue was discovered. This department is tasked with managing and administering the 693 Plan; monitoring and participating in Standard development and activities at FERC, NERC, and the SPP RE; serving as the liaison between AECC and the SPP RE; assisting the Compliance committee; and providing assistance to staff and other Compliance Managers as needed. The department head is the Compliance Manager for the 693 Plan who reports to the Executive Vice President and General Counsel.

EXPLAIN SENIOR MANAGEMENT'S ROLE AND INVOLVEMENT WITH RESPECT TO THE REGISTERED ENTITY'S COMPLIANCE PROGRAM, INCLUDING WHETHER SENIOR MANAGEMENT TAKES ACTIONS THAT SUPPORT THE COMPLIANCE PROGRAM, SUCH AS TRAINING, COMPLIANCE AS A FACTOR IN EMPLOYEE EVALUATIONS, OR OTHERWISE.

AECC's Board of Directors, CEO, and all levels of management are very active in AECC's Program. AECC's Board of Directors receives regular reports concerning compliance activities from the CEO, the Compliance Officer, and other Compliance Committee members. Several Board members are engaged by directly providing responses and data. They are also active in AECC's NERC Alerts program.

The CEO is instrumental in establishing AECC's corporate compliance environment, providing top-level support for compliance efforts, allocating necessary resources, approving delegation of responsibilities, and participating in Compliance Committee meetings as necessary.

The Compliance Committee's primary function is to monitor conformance with the Program. It meets at least quarterly and is active in monitoring compliance, awareness and training programs. The Compliance Committee monitors Plan administration, approves Plans, requires internal self-certification, monitors compliance reporting to the SPP RE, reviews incidents of noncompliance, and determines the need for self-reports. The Compliance Committee members participate regularly in training sessions and attend NERC and SPP Workshops.

All of the AECC Vice Presidents are active in promoting awareness and doing their part to ensure the reliability of the BES. They are very responsive to requests, and cooperate and assist when asked to do so.

The Compliance Officer, Compliance Committee, and Compliance Managers have the full support of the Board of Directors, CEO, and Senior Management Team for the Compliance Program and Compliance Plans.

(4) ANY ATTEMPT BY THE REGISTERED ENTITY TO CONCEAL THE VIOLATION(S) OR INFORMATION NEEDED TO REVIEW, EVALUATE OR INVESTIGATE THE VIOLATION.

YES ☐ **NO** ☒
IF YES, EXPLAIN

(5) ANY EVIDENCE THE VIOLATION(S) WERE INTENTIONAL (IF THE RESPONSE IS "YES," THE ABBREVIATED NOP FORM MAY NOT BE USED.)

YES ☐ **NO** ☒
IF YES, EXPLAIN

(6) ANY OTHER MITIGATING FACTORS FOR CONSIDERATION

YES ☒ **NO** ☐
IF YES, EXPLAIN

AECC received credit for self-reporting the violation in a timely manner and for cooperation by responding quickly and completely to information requests.

(7) ANY OTHER AGGRAVATING FACTORS FOR CONSIDERATION

YES ☐ **NO** ☒
IF YES, EXPLAIN

(8) ANY OTHER EXTENUATING CIRCUMSTANCES

YES ☐ **NO** ☒
IF YES, EXPLAIN

EXHIBITS:

SOURCE DOCUMENTS

Exhibit A - AECC's Self Report dated June 7, 2012
Exhibit C - AECC's Spot-Check Report dated February 1, 2013

MITIGATION PLANS

Exhibit B - AECC's MitPlan dated August 6, 2012
Exhibit E - AECC's MitPlan dated July 10, 2013
Exhibit D - SPP RE requests AECC to resubmit MP Certification of Completion dated September 11, 2012

CERTIFICATION BY REGISTERED ENTITY

Exhibit F - AECC's MitPlanCertOfCompletion dated December 16, 2015

VERIFICATION BY REGIONAL ENTITY

Exhibit G - SPP's MP Comp Review dated December 30, 2015
Exhibit H - SPP's MP Comp Verified dated December 30, 2015

OTHER RELEVANT INFORMATION:

NOTICE OF ALLEGED VIOLATION AND PROPOSED PENALTY OR SANCTION ISSUED
DATE: OR N/A ☒

SETTLEMENT DISCUSSIONS COMMENCED
DATE: 12/16/2015 **OR N/A** ☐

NOTICE OF CONFIRMED VIOLATION ISSUED
DATE: OR N/A ☒

SUPPLEMENTAL RECORD INFORMATION
DATE(S) OR N/A ☒

REGISTERED ENTITY RESPONSE CONTESTED
FINDINGS ☐ **PENALTY** ☐ **BOTH** ☐ **DID NOT CONTEST** ☒

HEARING REQUESTED
YES ☐ **NO** ☒
DATE
OUTCOME
APPEAL REQUESTED

Attachment B

AECC's Self-Report for PRC-005-1 submitted June 7, 2012

Self Report

Entity Name: Arkansas Electric Cooperative Corporation (AECC)

NERC ID: NCR01060

Standard: PRC-005-1

Requirement: PRC-005-1 R2.1.

Date Submitted: June 07, 2012

Has this violation previously been reported or discovered?: No

Entity Information:

Joint Registration Organization (JRO) ID:

Coordinated Functional Registration (CFR) ID:

Contact Name:

Contact Phone:

Contact Email:

Violation:

Violation Start Date: June 18, 2007

End/Expected End Date:

Region Initially Determined a Violation On:

Reliability Functions:

Is Possible Violation still occurring?: No

Number of Instances:

Has this Possible Violation been reported to other Regions?: No

Which Regions:

Date Reported to Regions:

Detailed Description and Cause of Possible Violation: AECC owns the Electric Cooperatives of Arkansas Hydropower Generating Station (HS2), which is a run-of-the-river hydro electric facility on the Arkansas River near Dumas, Arkansas. HS2 has three 36 MVA, 6.9 kV units, which are connected to the BES through a 40 MVA 6.9/115 kV step-up transformer and a 115 kV switching station. The AECC owned 115 kV switching station connects the HS2 facility to a 115 kV radial transmission line owned by Entergy. This radial transmission line terminates in Entergy’s Dumas substation, which is interconnected to the BES. The Dumas substation is the terminus for three (3) 115 kV transmission lines, including the line to HS2.

AECC has for decades had a relay maintenance and testing program. This program was revised in 2007 to comply with the requirements of PRC-005 and includes maintaining records for the relays that AECC either owns or has responsibility. As a part of the program, a Master Relay Maintenance Log (Master Log) is maintained to track the relay maintenance and testing. Test and maintenance dates are entered into the Master Log to ensure that relays are tested and maintained within the proper time intervals as defined in AECC’s program. Prior to the revision of the program in 2007, it was AECC’s common practice to test its relays within a twelve (12) year interval. The revision of the program in 2007 reduced this interval to five (5) years for electromechanical relays and 10 years for microprocessor based relays.

On May 1, 2012, during a routine review of the relay testing records and the

Self Report

Master Log, it was discovered that the HS2 generation relay test records had been omitted from the Master Log. Upon reviewing the HS2 generation files, it was further discovered that the test dates for 78 of the generator relays on the 6.9 KV bus at HS2 had exceeded the time intervals outlined in AECC's relay maintenance and testing program.

Of the 78 relays in question, 72 were tested between September 2004 and February 2005, and six (6) were tested between October 1998 and November 1999. Based on AECC's prior criteria of testing on 12 year intervals, six (6) relays exceeded the time interval and based on AECC's current criteria of testing on five (5) year intervals, all 78 relays exceeded the time interval. All other relays at HS2, including the generator step-up transformer and 115 KV switching station, have been tested within the proper time intervals.

Mitigating Activities:

Description of Mitigating Activities and Preventative Measure:

Date Mitigating Activities Completed:

Impact and Risk Assessment:

Potential Impact to BPS:

Actual Impact to BPS:

Description of Potential and Actual Impact to BPS: The impact to the BES would be minimal, if any. If one of the relays at HS2 were to fail to operate or misoperate a unit's generator breaker, the 115 kV tie breaker in the switching station would trip the entire facility thus preventing any cascading. The loss of generation would be the only impact the BES would experience. Because the units at HS2 are run-of-the-river hydro, they are available only when river flows are adequate. The units are not required to run nor are they needed for voltage support or system stability therefore; their impact on the BES is minimal.

Risk Assessment of Impact to BPS:

Additional Entity Comments:

Additional Comments		
From	Comment	User Name
Entity	AECC has developed a mitigation plan to address the potential violation. It is included in the AECC Potential Violation Self Report 6-7-12 document that has been uploaded as part of this self report.	Ronnie Frizzell

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	AECC Potential Violation Self Report 6-7-12.PDF	AECC Potential Violation Self Report 6-7-12	184,514

Attachment C

SPP RE’s Spot-Check Report dated February 1, 2013

Southwest Power Pool Regional Entity

HELPING OUR MEMBERS AND REGISTERED ENTITIES KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

PRC-005-1b
Spot Check Report

Arkansas Electric Cooperative Corporation

NERC ID# NCR01060

[redacted]

Date of Spot Check: February 1, 2013
Date of Report: February 28, 2013

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[redacted]

Executive Summary

A Spot Check of PRC-005-1b/R1 and R2, Transmission and Generation Protection System Maintenance and Testing, for Arkansas Electric Cooperative Corporation (AECC), NERC ID # - NCR01060, was conducted on February 1, 2013 based on a Self-Report of PRC-005-1b, R2. At the time of the Spot Check, AECC was registered for the Distribution Provider (DP), Generator Owner (GO), Generator Operator (GOP), Load Serving Entity (LSE), Purchase Selling Entity (PSE), Resource Planner (RP) and Transmission Owner (TO) function(s) in Southwest Power Pool Regional Entity (SPP RE).

AECC was evaluated for compliance with two requirements of the standard as of February 1, 2013. AECC submitted information and documentation to aid the SPP RE in their evaluation of compliance with the requirement. SPP RE reviewed and evaluated all information provided by AECC to assess compliance with the requirements applicable to the GO, TO and DP functions.

Based on the information and documentation provided, the Spot-Check team identified one (1) Possible Violation. A Possible Violation was identified for PRC-005-1b R1, Transmission and Generation Protection System Maintenance and Testing. There was one (1) requirement that remains under Open Enforcement Action and was reviewed by the Spot-Check team. There were no ongoing or recently completed mitigation plans associated with the standard requirements reviewed in the Spot Check. The Spot Check team notified AECC of six (6) Recommendations.

The SPP RE Spot Check Team Lead certifies that the Spot Check team adhered to all applicable requirements of the NERC Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP).

These Spot Check results are further explained in the Spot Check Findings section of this report which includes detailed information on the compliance determinations for the requirements.

Spot Check Process

The Spot Check process steps are detailed in the SPP RE CMEP. The SPP RE CMEP generally conforms to the United States Government Accountability Office Government Auditing Standards and other generally accepted audit practices.

Objectives

All Registered Entities are subject to Spot Checks for compliance with all reliability standards applicable to the functions for which the Registered Entity is registered. The Spot-Check objectives are to:

- Review compliance with the requirements of reliability standards that are applicable to AECC, based on the functions that AECC is registered to perform;
- Validate evidence of self-reported violations and previous self-certifications;
- Review the status of mitigation plans.

Scope

The Spot Check was performed on evidence which was in effect on February 1, 2013 to determine AECC's performance in meeting compliance to NERC Reliability Standards.

This Spot Check was conducted on NERC Standard: PRC-005-1b, Transmission and Generation Protection System Maintenance and Testing, Requirements R1 and R2.

Confidentiality and Conflict of Interest

Confidentiality and conflict of interest of the Spot Check team are governed under the SPP RE Delegation Agreement with NERC, and Section 1500 of the NERC Rules of Procedure. AECC was informed of SPP RE's obligations and responsibilities under the agreement and procedures. The work history for each Spot Check team member was provided to AECC. AECC was given an opportunity to object to a Spot Check team member's participation on the basis of a possible conflict of interest or the existence of other circumstances that could interfere with a Spot Check team member's impartial performance of duties. AECC had not submitted any objections by the stated fifteen day objection due date and accepted the Spot Check team member participants without objection. There have been no denials of or access limitations placed upon this Spot Check team by AECC.

Methodology

To accomplish the Spot Check objective, the SPP RE:

- Reviewed the standards/requirements identified in the scope above and evidence submitted

The Spot Check team reviewed documentation provided by AECC. Data, information and evidence submitted in the form of policies, procedures, e-mails, logs, studies, data sheets, etc. which were validated, substantiated and cross-checked for accuracy as appropriate.

Findings were based on the Spot Check team's knowledge of the Bulk Electric System, the NERC Reliability Standards and their professional judgment. All findings were developed based upon the consensus of the Spot Check team.

Spot Check Participants

The following is a listing of all personnel from the Spot Check team.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Spot Check Findings

Details of the findings for compliance for the scope identified for this Spot Check are outlined below:

1. **Reliability Standard # -** PRC-005-1

   Requirement # - R1

   Finding – Possible Violation

   Evidence Supporting Finding
   The Spot Check team reviewed the following evidence:
   - R1.1D TransmissionGenerationMaintProgram(PRC-005).pdf, Ver. 1.0, dated 02/05/2008

- R1.2D1 RelayTestingGeneralProcedures(PRC-005).jpg, Ver. 1, dated 09/25/2008
- R1.2D2 SubstationBatteryMaintenanceTasks(PRC-005).jpg, dated 12/13/2007
- R1.2D3 Generation Plant Battery Maintenance Guidelines.doc
- R1.2D4 MonthlySubstationVisualInspection(PRC-005).pdf, Rev. 1, dated 01/31/2006

AECC Protection System maintenance and testing program is provided in *R1.1D TransmissionGenerationMaintProgram(PRC-005).pdf* for transmission and generation facilities.

R1.1. Maintenance and testing intervals and their basis:
AECC's program defines the maintenance and testing intervals as five (5) years for electro-mechanical protective relays and ten (10) years for microprocessor based protective relays. Associated communication system intervals are defined as five (5) years for non-microprocessor based and ten (10) years for microprocessor based equipment. Station battery intervals are defined as a monthly inspection and three (3) years for maintenance and testing. The basis for all intervals is AECC historical practices or manufacturer's guidelines.

R1.2. Summary of maintenance and testing procedures:
AECC provided various summaries to support the maintenance and testing procedure. *R1.2D1 RelayTestingGeneralProcedures(PRC-005).jpg* summarizes the procedure for testing protective relays and refers to the use of factory manuals. AECC stated in *R1.1D TransmissionGenerationMaintProgram(PRC-005).pdf* that voltage and current sensing devices will be maintained and tested according to common industry practices or manufacturer's guidelines. AECC provided evidence of substation battery maintenance tasks and generation plant battery maintenance guidelines that summarized AECC's procedures in *R1.2D2 SubstationBatteryMaintenanceTasks(PRC-005).jpg* and *R1.2D3 Generation Plant Battery Maintenance Guidelines.doc* respectively. *R1.2D4 MonthlySubstationVisualInspection(PRC-005).pdf* shows that breaker trip coils and indicating lights are checked during monthly station physical inspections.

Summary:
The Spot Check team did not find sufficient evidence of defined maintenance and testing intervals for voltage and current sensing devices, nor DC control circuitry. (R1.1)

The Spot Check team did not find sufficient evidence of data used to support the historical practice basis of intervals. (R1.1)

The Spot Check team did not find sufficient evidence of summaries of maintenance and testing procedures for voltage and current sensing devices nor DC control circuitry. (R1.2)

The Spot Check team discovered areas of possible non-compliance based on the evidence presented by AECC and reviewed by the Spot Check team.

2. **Reliability Standard # -** PRC-005-1

Requirement # - R2

Finding - Open Enforcement Action (Violation ID SPP2012010432)

On August 6, 2012, AECC submitted a Mitigation Plan regarding the possible violations it had reported in its Self Report of PRC-005 R2 on June 7, 2012 under Violation ID (SPP2012010432).

Evidence Supporting Finding
The Spot Check team reviewed the following evidence:

- R2.1D1 RelayCarrierSchedule(PRC-005).pdf, dated 11/07/2012
- R2.1D2 BatterySchedule(PRC-005).pdf, dated 12/16/2012
- R2.1D3 RelayLogProcedure (PRC-005).pdf, dated 08/10/2012
- Generation folder - 17 generation facilities from RATSTATS sampling
- Substation folder - 15 transmission facilities from RATSTATS sampling
- ER-01- Battery tests prior to 2012 for Whillock Unit 1, 2 and 3.
- ER-02 -Verify last relay test date for Fitzhugh Unit 2 relay 59GN and 81

R2.1D1 RelayCarrierSchedule(PRC-005).pdf is the testing schedule and summary record for protective relays and associated communication systems. *R2.1D2 BatterySchedule(PRC-005).pdf* is the testing schedule and summary record for generation and substation batteries. AECC's detailed testing and maintenance records show that most protective relays, associated communication systems, and station batteries were tested within the AECC defined intervals once augmented by evidence provided for *ER-01* and *ER-02*. However, not all Protection Systems devices were maintained and tested within the defined intervals. The Spot Check Team found that several monthly battery inspections were missed and at least one relay missed the defined interval based on RATSTATS sampling reviewed by the Spot Check team. The Spot Check team also sent AECC a list of questions as documented in the *AECC RAT-STATS list for review 130128* and AECC provided written responses to each question.

Summary:
The Spot Check team did not find sufficient evidence to indicate voltage and current sensing devices and DC control circuitry had a defined interval, as identified in R1, to perform testing and maintenance. The commissioning tests and breaker operations were given as evidence for R2.1 with no defined interval for subsequent testing and maintenance.

Examples:
AECC did not have evidence to show that current and voltage sensing devices had ever been tested at Bailey Station. AECC did not have evidence of testing on Fulton Switching Station-Okay relay 62BF. AECC did not have evidence of any DC circuitry tests on Oswald Unit 8 Relay 59. (R2.1)

At the time of the Spot Check, AECC had an Open Enforcement Action regarding this Requirement.

Compliance Culture

AECC's compliance culture was not reviewed by the Spot Check team.

The Pre-Audit Survey, RSAW and evidence were submitted on time and were satisfactorily written. AECC was very responsive to information requests during the Spot Check. This, coupled with the initial submittals, enabled and contributed to the timely completion of the Spot Check by the Spot Check team.

Additional information pertaining to the compliance culture of AECC can found in the Pre-Audit Survey.

Recommendations

The audit team notified AECC of six (6) Recommendations. The specific details of each Recommendation are described below.

1. Enhance protective component testing result forms to identity overall results of tests (pass/fail) and any maintenance required.
2. Review and update Transmission and Generation Protection System Maintenance and Testing Program (v1.0) to reflect current processes. This document has not been revised since 2008.

3. Evaluate PRC-005-2 Table 1-3 requirement to verify current and voltage signal values are provided to protective relays in future revisions of the Transmission and Generation Protection System Maintenance and Testing Program.
4. Revise Transmission and Generation Protection System Maintenance and Testing Program to include flexibility or time allowance used to extend testing intervals for unexpected events.
5. Consider removing the monthly visual inspection requirement from Testing and Maintenance Program or place controls in place to meet monthly obligation.
6. Substation Battery Maintenance Tasks and Generation Plant Battery Maintenance Guidelines provided in R1.2 evidence should be referenced in the Protective System Testing and Maintenance Program v1.0 document to clarify the summary of testing and maintenance procedures.

Post Spot Check Activities

This report was reviewed and approved by:
Ronald W. Ciesiel
General Manager, SPP RE
March 8, 2013

Attachment D

AECC's Mitigation Plan designated as SPPMIT007801-1 for PRC-005-1 submitted July 10, 2013

Mitigation Plan

Registered Entity: Arkansas Electric Cooperative Corporation

Mit Plan Code	NERC Violation ID	Requirement	Violation Validated On	Mit Plan Version
	SPP2012010432	PRC-005-1 R2	null	2

Mitigation Plan Submitted On: July 10, 2013
Mitigation Plan Accepted On: July 11, 2013
Mitigation Plan Proposed Completion Date: July 01, 2016
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by AECC On:
Mitigation Plan Completion Verified by SPPRE On:
Mitigation Plan Completed? (Yes/No): No

Section A: Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Section B: Registered Entity Information

B.1 Identify your organization:

Entity Name: Arkansas Electric Cooperative Corporation
NERC Compliance Registry ID: NCR01060
Address: Box 194208
Little Rock AR 72219-4208

B.2 Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Ronnie Frizzell
Title: Director NERC Compliance
Email: ronnie.frizzell@aecc.com
Phone: 501-570-2433

Section C: Identification of Reliability Standard Violation(s) Associated with this Mitigation Plan

C.1 This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
SPP2012010432	06/18/2007	PRC-005-1 R2
Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:		

C.2 Brief summary including the cause of the violation(s) and mechanism in which it was identified above:

On May 1, 2012, during a routine review of the AECC's relay testing records and AECC's Master Relay Maintenance Log (Master Log), it was discovered that the HS2 generation relay test records had been omitted from the Master Log. Upon reviewing the HS2 generation relay test files, it was further discovered that the test dates for 78 of the generator relays on the 6.9 KV bus at HS2 had exceeded the time intervals outlined in AECC's current relay maintenance and testing program.

Of the 78 relays in question, 72 were tested between September 2004 and February 2005, and six (6) were tested between October 1998 and November 1999. Based on AECC's prior criteria of testing on 12 year intervals, six (6) relays exceeded the time interval and based on AECC's current criteria of testing on five (5) year intervals, all 78 relays exceeded the time interval. All other relays at HS2, including the generator step-up transformer and 115 KV switching station, have been tested within the proper time intervals.

ADDENDUM

In February 2013 SPP RE conducted a spot check of PRC-005-1b (SPP2013011836). As part of the spot check the SPP RE reviewed the open enforcement action (SPP2012010432) involving PRC-005-1b R2. AECC provided the SPP RE a mitigation plan addressing the spot check findings on April 19, 2013. The SPP RE requested that AECC revise its mitigation plan provided on August 6, 2012 for SPP2012010432 to address the spot check findings for R2. This addendum is to comply with the SPP RE request.

The spot check found: â€œThe Spot Check team did not find sufficient evidence to indicate voltage and current sensing devices and DC control circuitry had a defined interval, as identified in R1, to perform testing and maintenance. The commissioning tests and breaker operations were given as evidence for R2.1 with no defined interval for subsequent testing and maintenance.

Examples:
AECC did not have evidence to show that current and voltage sensing devices had ever been tested at Bailey Station. AECC did not have evidence of testing on Fulton Switching Station-Okay relay 62BF. AECC did not have evidence of any DC circuitry tests on Oswald Unit 8 Relay 59. (R2.1)

At the time of the Spot Check, AECC had an Open Enforcement Action regarding this Requirement.â€

C.3 Provide any relevant information regarding the identification of the violation(s) associated with this Mitigation Plan:

Upon discovery of the discrepancy AECC's Transmission Operations Department conducted an investigation and discovered that the omission had occurred in 2007 when the Master Log was compiled as a part of AECC's compliance with PRC-005. In addition, a review of the HS2 generator files was conducted and revealed that the relay test for several relays at HS2 had exceeded the test intervals as outlined in AECC's relay maintenance and testing program.

ADDENDUM

No additional information

Section D: Details of Proposed Mitigation Plan

D.1 Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

On May 2, 2012, a relay technician was dispatched to HS2 to begin testing the relays in question. Testing was suspended during the period of May 3-14 due to operational and other issues at HS2. Relay testing resumed on May 14 and concluded on May 24. The results of the tests showed that none of the relays had failed, all relays tested were found to be operational and within allowable tolerances, and no other issues were discovered.

Beginning on May 7, the entire Transmission Operations Relay Section conducted a review of all relay maintenance files to ensure no other relay test files or updates were omitted from the Master Log. No other omissions were discovered. This was completed on May 11.

The following actions were also completed during May.

1. The Master Log was updated to include the omitted HS2 relays following the review completed on May 11 (see above)
2. All testing dates on the Master Log were checked to ensure all relays were within test intervals May 11. No other relays were found to be outside the appropriate test intervals.
3. All relay test files were consolidated into a central location May 31
4. The Principal Engineer Transmission Operations began reviewing and drafting the necessary changes to the work procedures, processes and documentation identified in this mitigation plan to ensure AECC's program is up to date.

Additional mitigation steps include:

1. Adoption of work procedures to provide for tracking the sign out and sign in of relay maintenance files for relay tests and other maintenance updates. The sign in/out sheet was implemented beginning May 31.
2. Reconcile the Master Log with other AECC records. Completed as of July 31. No other records were found to have been omitted.
3. Adoption of a work procedure to conduct regular reviews, no less than once a quarter, and updates to the Master Log utilizing the weekly relay section reports and testing records. This procedure will be completed and implemented by August 10

The time each step of the Mitigation Plan was or will be completed is included with each step in Section D.1. The proposed completion date for the entire Mitigation Plan is August 10, 2012.

UPDATE TO ORIGINAL MITIGATION PLAN SUBMITTED AUGUST 6, 2012.

Each of the actions and additional mitigation steps listed above were completed by the actual or proposed dates shown. The original mitigation plan above was completed by August 10, 2012 as proposed.

ADDENDUM

1. AECC has begun the process of analyzing its records for voltage and current sensing devices and DC control circuitry at all of its BES facilities. The result of this analysis will be a list of any facilities which will require testing.

2. Testing will be conducted at all BES facilities identified by the analysis in step 1 above to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Once a facility is tested it will be current with the test intervals defined in AECC protection system maintenance and testing program.

It is estimated that there could be 50 transmission and generation elements (i.e. line terminals, busses and generating units) involved with this activity. The AECC protection system maintenance and testing program currently allows a one year implementation period for devices to achieve the programâ€™s requirements. In order to prevent AECC from being in conflict with its protective system maintenance and testing program, this requirement is being suspended for voltage and current sensing devices and DC circuitry until this mitigation plan is completed.

3. At Bailey Station, AECC will conduct testing of the voltage and current sensing devices. The voltage and current sensing devices were found to be functionally capable and performing properly. This was completed on May 16, 2013.

4. For the Fulton to Okay line terminal at Fulton, AECC will conduct testing of the 62BF relay. The 62BF function was tested and found to be performing properly. This was completed on January 30, 2013.

5. At Oswald Unit 8, AECC found evidence of the DC circuitry being functionally capable and performing properly and the test report for the 59 relay. The DC circuitry evidence was dated February 27, 2008, and the 59 relay was tested on February 18, 2010. It is unknown why this evidence was not provided at the time of the spot check.

D.2 Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: July 01, 2016

D.3 Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 2 of 50	10/01/2013	
Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan	Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 8 of 50	01/01/2014	
Conduct analysis of records for voltage and current sensing devices and DC control circuitry at all AECC BES facilities	Conduct analysis of records for voltage and current sensing devices and DC control circuitry at all AECC BES facilities	01/01/2014	
Conduct testing of at least 6 BES	Conduct testing of at least 6 BES	04/01/2014	

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
facilities identified by the analysis in step 1 of the mitigation plan.	facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 14 of 50		
Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 16 of 50	07/01/2014	
Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 18 of 50	10/01/2014	
Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 24 of 50	01/01/2015	
Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 30 of 50	04/01/2015	
Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and	07/01/2015	

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
	performing properly. Estimated total completion: 32 of 50		
Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 2 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 34 of 50	10/01/2015	
Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 40 of 50	01/01/2016	
Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of at least 6 BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 46 of 50	04/01/2016	
Conduct testing of the remaining BES facilities identified by the analysis in step 1 of the mitigation plan.	Conduct testing of the remaining BES facilities identified by the analysis in step 1 of the mitigation plan to determine that the voltage and current sensing devices and DC control circuitry is functionally capable and performing properly. Estimated total completion: 50 of 50	07/01/2016	

D.4 Additional Relevant Information (Optional)

Section E: Interim and Future Reliability Risk

E.1 Abatement of Interim BPS Reliability Risk

While your organization is implementing the Mitigation Plan proposed in Section D of this form, the reliability of the Bulk Power System may remain at higher risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are, or may be, known or anticipated: (i) identify any such risks or impacts; and (ii) discuss any actions that your organization is planning to take or is proposing as part of the Mitigation Plan to mitigate any increased risk to the reliability of the bulk power system while the Mitigation Plan is being implemented:

AECC does not believe there were or are any remaining risks to the Bulk Power System because:
1. Failure or misoperation of any of the relays in question would only result in removal of generation from the BPS. Because the generators at HS2 are run-of-the-river hydro electric units, only available when river conditions allow, and the units are not needed for system voltage support or system stability, any impact to the BPS would be minimal, if any.
2. The relays in question have been tested and found to be in proper order.
3. The review of AECC's records has not revealed any additional relays missing from the Master Log nor out of their test interval.

ADDENDUM

AECC does not believe there will be any additional impacts to the BES.

E.2 Prevention of Future BPS Reliability Risk

Describe how successful completion of the Mitigation Plan as laid out in Section D of this form will prevent or minimize the probability that your organization incurs further violations of the same or similar reliability standards requirements in the future:

The implementation of the work process improvements described in Section D.1 above are expected to minimize the potential for further violations of PRC-005 R2.1 for reasons of documents and records not being properly logged. The implementation of a check out system for the relay test files should provide better tracking of the files. The reconciliation of the Master Log should ensure that all relays for which AECC is responsible are included in the relay maintenance and testing program. The implementation of monthly reviews should ensure that maintenance and testing is being properly logged and the schedule for maintenance and testing is on track and being followed in a timely manner.

ADDENDUM

The analysis of AECCâ€™s records will provide a thorough indication of where potential issues may exist and where AECCâ€™s records need updating.
The completion of all testing of voltage and current sensing devices and DC control circuitry will not only verify the performance of these facilities but it will bring these facilities in line with the requirements and time intervals in AECCâ€™s testing and maintenance program.

E.3 Your organization may be taking or planning other action, beyond that listed in the Mitigation Plan, as proposed in Section D.1, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements listed in Section C.1, or of other reliability standards. If so, identify and describe any such action, including milestones and completion dates:

The improvements AECC has taken in monitoring its maintenance & testing program are expected to minimize the probability of further violations.

Section F: Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

(a) Submits the Mitigation Plan, as laid out in Section D, to the Regional Entity for acceptance and approval by NERC, and

(b) If applicable, certifies that the Mitigation Plan, as laid out in Section D of this form, was completed (i) as laid out in Section D of this form and (ii) on or before the date provided as the 'Date of Completion of the Mitigation Plan' on this form, and

(c) Acknowledges:

1. I am Vice President, Power Production and Delivery of Arkansas Electric Cooperative Corporation
2. I am qualified to sign this Mitigation Plan on behalf of Arkansas Electric Cooperative Corporation
3. I have read and understand Arkansas Electric Cooperative Corporation's obligations to comply with Mitigation Plan requirements and ERO remedial action directives as well as ERO documents, including, but not limited to, the NERC Rules of Procedure and the NERC CMEP currently in effect or the NERC CMEP-Province of Manitoba, Schedule B currently in effect, whichever is applicable.
4. I have read and am familiar with the contents of the foregoing Mitigation Plan.
5. Arkansas Electric Cooperative Corporation Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authorities in Canada.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Jonathan Oliver

Title: Vice President, Power Production and Delivery

Authorized On: July 03, 2013

Attachment E

AECC's Certification of Mitigation Plan Completion for PRC-005-1 submitted December 16, 2015

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Arkansas Electric Cooperative Corporation

NERC Registry ID: NCR01060

NERC Violation ID(s): SPP2012010432

Mitigated Standard Requirement(s): PRC-005-1 R2.

Scheduled Completion as per Accepted Mitigation Plan: July 01, 2016

Date Mitigation Plan completed: November 13, 2015

SPPRE Notified of Completion on Date: December 16, 2015

Entity Comment: Through the dedication and hard work of AECC's personnel, AECC was able to complete this mitigation plan seven months ahead of schedule.

Additional Comments

From	Comment	User Name
Entity	In addition to AECC Certificate of Completion, AECC has uploaded sixteen files, not five as reported in the Certificate of Completion, as evidence of AECC's completion of the mitigation plan.	Ronnie Frizzell

Additional Documents

From	Document Name	Description	Size in Bytes
Entity	AECC Potential Violation Self Report 6-7-12.PDF	AECC Potential Violation Self Report 6-7-12	184,514
Entity	AECC Certificate of Completion.PDF	AECC Certificate of Completion	45,811
Entity	Scan of relay file checkout sheet DOC080312-08032012104306.pdf	AECC Relay File Checkout Sheet	413,132
Entity	relay master log procedure-08102012145733.pdf	AECC Relay Master Log Procedure	200,240
Entity	relay test master log updated copy-08202012140625.pdf	AECC Relay Test Master Log Updated Copy	315,626
Entity	copy master log-08202012130603.pdf	AECC Master Log	455,078
Entity	HS2 File 5.pdf	HS2 Relay Test Files 5 of 11	2,053,555
Entity	HS2 File 1.pdf	HS 2 Relay Test File 1 of 11	9,244,291
Entity	HS2 File 2.pdf	HS2 Relay Test File 2 of 11	2,094,501

Additional Documents			
From	**Document Name**	**Description**	**Size in Bytes**
Entity	HS2 File 3.pdf	HS 2 Relay Test File 3 of 11	8,884,882
Entity	HS2 File 4.pdf	HS 2 Relay Test File 4 of 11	2,127,175
Entity	HS2 File 6.pdf	HS 2 Relay Test File 6 of 11	3,461,746
Entity	HS2 File 7.pdf	HS 2 Relay Test File 7 of 11	11,855,163
Entity	HS2 File 8.pdf	HS 2 Relay Test File 8 of 11	2,218,718
Entity	HS2 File 9.pdf	HS 2 Relay Test File 9 of 11	1,820,903
Entity	HS2 File 10.pdf	HS 2 Relay Test File 10 of 11	411,981
Entity	HS2 File 11.pdf	HS 2 Relay Test File 11 of 11	1,923,207
Entity	relay test file checkout procedure-08202012140201.pdf	AECC Relay Test File Checkout Procedure	201,768
Entity	HS2 File 12.pdf	HS2 File 12	1,263,345
Entity	HS2 Plant Relay Test List.xls	HS2 Plant Relay Test List	33,792
Entity	AECC PRC-005-1 R2 Mit Plan Certificate of Completion.pdf	AECC PRC-005-1 R2 Mitigation Plan Certificate of Completion	193,576

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Jonathan Oliver

Title: Vice President, Power Production and Delivery

Email: Jonathan.Oliver@AECC.com

Phone: 1 (501) 570-2488

Authorized Signature ______________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Attachment F

SPP RE's Verification of Mitigation Plan Completion for PRC-005-1 dated December 30, 2015

[redacted]

Mitigation Plan Milestone/Completion Review

Registered Entity: Arkansas Electric Cooperative Corporation (AECC)

Registry ID: NCR01060

NERC Violation ID: SPP2012010432

Reliability Standards and Requirement addressed by the plan:

PRC-005-1

R2 *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:*

R2.1. *Evidence Protection System devices were maintained and tested within the defined intervals.*

R2.2. *Date each Protection System device was last tested/maintained*

NERC Mitigation Plan No: SPPMIT007801-1

Has the entity provided its Certification of Completion? Yes

Date of Registered Entity's Certification of Completed Mitigation Plan: 12/16/2015

Date Certification Received by SPP RE: 12/16/2015

Has the entity supplied data or information sufficient for the Enforcement Staff to independently verify that all required actions described in the Mitigation Plan have been completed? Yes

Date Final Installment of Evidence Received: 12/16/2015

Mitigation Plan Milestone Review and Evidence of Completion Review:

Milestones (if applicable)	**Evidence Under Review** (*Document title, file name, date of documentation, and document revision number*) (Ex. *Facilities Methodology*, 101112_MPEVD_Entity, 11/12/10, Rev. 2)	**Proposed Completion Date**	**Completion Date**	**Review Date**	**Comments or Suggestions (Applicable to Mitigation Plan)**
N/A	**AECC Potential Violation Self Report 6-7-12.pdf**	**07/01/2016**	**11/13/2015**	**12/30/2015**	**Applicable**

	AECC PRC-005 BES Impact Worksheet.xls	07/01/2016	11/13/2015	12/30/2015	Applicable
	PRC-005-1 R2 Analysis.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	PRC-005 R2 Mitigation Plan April 2014 Evidence - 1 of 2.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	PRC-005 R2 Mitigation Plan April 2014 Evidence - 2 of 2.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	PRC-005 Mitigation Plan Evidence 2014 Q3.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	PRC-005-1 R2 Mitigation Plan Evidence Email 12-18-14.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
10	PRC-005-1 R2 Mitigation Plan Evidence for Q3 2015.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	PRC-005-1 R2 Mitigation Plan Evidence for Q4 2015.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PRC-005-1 R2 Mitigation Plan Evidence.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	PRC-005-1 R2 Mitigation Plan Milestone.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	AECC PRC-005 R2 MP Milestone 7-1-14 (1 of 3)	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Dell 500 SS Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Dell 500 SS Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 5 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 5 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 6 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 6 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 7 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 7 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	PRC-005-1 R2 Mitigation Plan Evidence (1 of 3).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	AECC PRC-005 R2 MP Milestone 7-1-14 (2 of 3)	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 7 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 7 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Sub - GSU 1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Sub - GSU 1 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Sub - GSU 2 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Sub - GSU 2 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable

5	Oswald Plant Sub - GSU 3 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Sub - GSU 3 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Unit 8 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Unit 8 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Unit 9 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant Unit 9 Sensing Device.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	PRC-005-1 R2 Mitigation Plan Evidence (2 of 3).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	AECC PRC-005 R2 MP Milestone 7-1-14 (3 of 3)	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Fulton 115kv SS - GSU Breaker Sensing Device update.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 3 Breaker 52-3 CT Trouble Report.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	Oswald Plant - Unit 3 Sensing Device update.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
5	PRC-005-1 R2 Mitigation Plan Evidence (3 of 3).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	2015 Q1 Mitigation Plan Evidence	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Bailey 161kV Switching Station - Moses Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Bailey 161kV Switching Station - Moses Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Bailey 161kV Switching Station - Moses Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Bailey 161kV Switching Station - Newport Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Bailey 161kV Switching Station - Newport Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Bailey 161kV Switching Station - Newport Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Dell 161kV Switching Station	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Dell 161kV Switching Station - Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Dell 161kV Switching Station - Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	HS9 Whillock Plant 3 - Unit 3 and GSU 3	07/01/2016	11/13/2015	12/30/2015	Applicable
7	HS9 - Plant 3 Unit 3 and GSU3 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	HS9 - Plant 3 Unit 3 and GSU3 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	McClellan 115kV Switching Station - Camden Maguire Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	McClellan 115kV Switching	07/01/2016	11/13/2015	12/30/2015	Applicable

	Station - Camden Maguire Line Sensing Devices.pdf				
7	McClellan 115kV Switching Station - Camden Maguire Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	McClellan 115kV Switching Station - Camden North Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	McClellan 115kV Switching Station - Camden North Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	McClellan 115kV Switching Station - Camden North Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	2015 Q2 Mitigation Plan Evidence	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS9 Whillock Plant 1 - Unit 1 and GSU 1	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS9 - Plant Unit 1 and GSU1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS9 - Plant Unit 1 and GSU 1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS9 Whillock Plant 2 - Unit 2 and GSU 2	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS9 - Plant 2 Unit 2 and GSU 2 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS9 - Plant 2 Unit 2 and GSU 2 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	Bailey 161kV SS - Main Bus	07/01/2016	11/13/2015	12/30/2015	Applicable
11	Bailey 161kV Switching Station - Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	Bailey 161kV Switching Station - Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	Bailey Plant - Unit 1 and GSU 1	07/01/2016	11/13/2015	12/30/2015	Applicable
11	Bailey Plant - Unit 1 and GSU 1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	Bailey Plant - Unit 1 and GSU 1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	Blytheville North Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	Blytheville North Voltage and Current Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	East Centerton	07/01/2016	11/13/2015	12/30/2015	Applicable
8	East Centerton Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	East Centerton Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 ECA 115kV SS - 115kV Main Line	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 - SS Main Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 - SS Main Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 ECA 115kV SS - Dumas Line	07/01/2016	11/13/2015	12/30/2015	Applicable

8	HS2 - SS Dumas Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 - SS Dumas Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 ECA 115kV SS - Main Bus	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 - SS Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	HS2 - SS Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
8	Fitzhugh Plant and Switching Station BES Elements	07/01/2016	11/13/2015	12/30/2015	Applicable
8	Fitzhugh 161kV Switching Station - 161kV Main Bus	07/01/2016	11/13/2015	12/30/2015	Applicable
8	Fitzhugh SS - 161kV Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - 161kV Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh 161kV Switching Station - Helburg Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - Helburg Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - Helburg Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh 161kV Switching Station - Igo Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - Igo Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - Igo Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh 161kV Switching Station - Ozark Dam Line	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - Ozark Dam Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh SS - Ozark Dam Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh Plant (GT) - GT & GSU 2	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh Plant - GT & GSU 2 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh Plant - GT & GSU 2 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh Plant (ST) - ST & GSU 1	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh Plant - ST & GSU1 Sensing Devices .pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
7	Fitzhugh Plant - ST & GSU1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton CT1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton CT1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton SS Couch Control Circuity.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable

4	Fulton SS Couch Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton SS Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton SS Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton SS Okay Control Circuity.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
4	Fulton SS Okay Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 ECA 115kV SS - 115kV Main Line	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - SS Main Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - SS Main Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 ECA 115kV SS - Dumas Line	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - SS Dumas Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - SS Dumas Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 ECA 115kV SS - Main Bus	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - SS Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - SS Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 ECA Plant 1 - Unit 1 & GSU 1	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - Plant Unit 1 and GSU 1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - Plant Unit 1 and GSU 1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 ECA Plant 2 - Unit 2 & GSU 2	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - Plant Unit 2 and GSU 2 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - Plant Unit 2 and GSU 2 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 ECA Plant 3 - Unit 3 & GSU 3	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - Plant Unit 3 and GSU 3 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 - Plant Unit 3 and GSU 3 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	HS2 Plant Relay Test List.xls	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_1[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_2[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_3[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_4[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_5[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_6[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_7[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable

1	HS2_File_8[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_9[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_10[2].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2_File_11[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS2 File 12.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS9 SS Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS9 SS Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS9 SS Morrilton East Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS9 SS Morrilton East Line Voltage and Current Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS9 SS Pinnacle Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	HS9 SS Pinnacle Line Voltage and Current Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	Helena Industrial - Gillette Line	07/01/2016	11/13/2015	12/30/2015	Applicable
6	Helena Industrial - Gillette Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	Helena Industrial - Gillette Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	Helena Industrial - Ritchie Line	07/01/2016	11/13/2015	12/30/2015	Applicable
6	Helena Industrial - Ritchie Line Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
6	Helena Industrial - Ritchie Line Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove 500kV SS Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove 500kV SS Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove Plant 1 CT1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove Plant 1 CT1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove Plant 2 ST1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove Plant 2 ST1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove Plant 3 CT2 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Magnet Cove Plant 3 CT2 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	McClellan 115kV Switching Station - Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	McClellan 115kV Switching Station - Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	McClellan Plant - Unit 1 and GSU 1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
11	McClellan Plant - Unit 1 and GSU 1	07/01/2016	11/13/2015	12/30/2015	Applicable

	Sensing Devices.pdf				
2	Osage Creek 161kV Main Bus Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Osage Creek 161kV Main Bus Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Osage Creek 161kV Transfer Tie Breaker Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
2	Osage Creek 161kV Transfer Tie Breaker Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 1 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 1 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 2 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 2 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 3 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 3 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 4 Control Circuitry.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
3	Oswald Unit 4 Sensing Devices.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
13	AECC Certificate of Completion.pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	copy_master_log-08202012130603[2].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	relay_master_log_procedure-08102012145733[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	relay_test_file_checkout_procedure-08202012140201[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	relay_test_master_log_updated_copy-08202012140625[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
1	Scan_of_relay_file_checkout_sheet_DOC080312-08032012104306[1].pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Magnet Cove Relays Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Magnet Cove Sensing Devices Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Dell 500 Battery and Charger Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Dell 500 Communication Equipment Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Dell 500 Control Circuits Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Dell 500 Relays Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Dell 500 Sensing Devices Portfolio(PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS HS9 Sw Station Trip Paths Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable

N/A	PROTSYS Magnet Cove Battery and Charger Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Magnet Cove Communication Equipment Portfolio (PRC-005-2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable
N/A	PROTSYS Magnet Cove Control Circuits Portfolio (PRC-005-R2).pdf	07/01/2016	11/13/2015	12/30/2015	Applicable

Actual Violation End Date (*the date the Registered Entity returned to compliance based on the supplied evidence)*:

The Violation Actually was completed on 11/13/2015 based on the last test result which was the Interruption Report on page 4 of the McClellan Plant – Unit 1and GSU 1 Control Circuitry.pdf document located in the McClellan Plant – Unit 1 GSU 1 Mitigation Evidence zip file.

Actual Final Completion Date of Mitigation Plan (*the date in time that the reviewer can actually verify the mitigation plan was complete based on the supplied evidence and the receipt of a mitigation plan completion certification/ please explain why date was chosen*):

SPP RE received the Certification of a Completed Mitigation Plan and final additional supporting evidence on December16, 2015 and has determined from the evidence submitted that the Actual Final Completion Date of the Mitigation Plan is November 13, 2015.

Any other comments for suggested changes or requests for additional evidence (*please denote the specific item of evidence or milestone being requested*):

None

Statement by SPP RE verifying completion of the Mitigation Plan / Milestone (*In essence, detail what actions were taken by the entity to demonstrate compliance*):

SPP has concluded that on the basis of the evidence presented that the entity has completed the mitigation activities associated with PRC-005-1 R2 on November 13, 2015.

Have all required actions described in the Mitigation Plan been completed? **Yes**

Review Performed by: **Bob Reynolds**

Date Review Performed: **December 30, 2015**