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May 1, 2018

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HAND DELIVERED

Gwen R. Pinson
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RECEIVED
MAY 01 2018
PUBLIC SERVICE COMMISSION

RE: Administrative Case No. 345

Dear Ms. Pinson:

Pursuant to the Commission's March 1, 1993 Order in Administrative Case No. 345, please find enclosed and accept for filing a copy of AEP East/PJM and AEP West/SPP Emergency Operating Plan Version 20. Due to its voluminous nature, and in accordance with past practice, the Company is filing the copy of the Plan in electronic form on a CD.

Also being filed are the original and ten copies of the Company's motion for confidential treatment for those portions of the AEP East/PJM and AEP West/SPP Emergency Operating Plan identified in the enclosed affidavit of Michael R. Richardson as being confidential.

Please do not hesitate to contact me if you have any questions

Very truly yours,

Mark R. Overstreet

MRO

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 01 2018

PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation Into Electric Utilities Emergency Response Plans) Administrative Case No. 345

* * * * * * * *

MOTION FOR CONFIDENTIAL TREATMENT

Kentucky Power Company moves the Public Service Commission of Kentucky pursuant to 807 KAR 5:001, Section 13 for an Order granting confidential treatment to the identified confidential information and documents ("Confidential Information") filed in connection with Kentucky Power's Emergency Operations Plan submitted for its update with the Commission pursuant to the Commission's order in Administrative Case No. 345. This motion is supported by the Affidavit of Michael R. Richardson ("Richardson Affidavit") attached as Exhibit A.

The Emergency Operations Plan is sensitive as a whole but there are portions of the filing that include Critical Energy Infrastructure Information ("CEII").[1] This information is declared by the Federal Energy Regulatory Commission ("FERC") to be exempt from public disclosure. Specifically, Kentucky Power is seeking confidential treatment for the information identified as "Confidential Information" in Paragraph 5 of the Richardson Affidavit:

Vol/Pg #	Confidential Information
VI/9	Description of critical points on the generation and transmission system and describes the dependent engineering relationship.
VI/10-11	Operations guide relates to the engineering and design of existing infrastructure of a specific portion of the system.

[1] Richardson Affidavit at ¶¶ 4-5.

Vol/Pg #	Confidential Information
VI/12-13	Description of critical points on the generation and transmission system and describes the dependent engineering relationship.
VI/14-16	Load shed plan provides information regarding the vulnerability of existing infrastructure.
VI/35-36	Specific description of units equipped with a certain power stabilizer.
Appendix VII/1-6	Contact names and information of personnel involved in the emergency response operations. Public disclosure of this list would provide persons seeking to harm the generation and transmission system a list of individuals both within Kentucky Power and APESC and contacts at other companies who are responsible for securing the system and ensuring its continued operation and could be used to interfere with the performance of their duties.

Pursuant to 807 KAR 5:001, Section 13, Kentucky Power is filing under seal those portions of the Emergency Operations Plan containing confidential information with the confidential portions highlighted in yellow or otherwise indicated as being confidential. Kentucky Power is also filing redacted versions of the filing. Kentucky Power will notify the Commission when it determines the information for which confidential treatment is sought is no longer confidential.

A. The Statutory Standard.

KRS 61.878(1)(m)(1)(f) exempts records from public inspection that would have a reasonable likelihood of threatening the public safety by exposing a vulnerability in preventing, protecting against, mitigating, or responding to a terrorist act, including:

> Infrastructure records that expose a vulnerability referred to in this subparagraph through the disclosure of the location, configuration, or security of critical systems, including public utility critical systems. These critical systems shall include but not be limited to information technology, communication, electrical, fire suppression, ventilation, water, wastewater, sewage, and gas systems;

KRS 61.878(1)(k) further exempts "all public records or information the disclosure of which is prohibited by federal law or regulation" from disclosure under the Open Records Act. FERC Rule 18 C.F.R. § 388.113(c) states that CEII:

means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:

(i) Relates details about the production, generation, transportation, transmission, or distribution of energy;

(ii) Could be useful to a person in planning an attack on critical infrastructure;

(iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and

(iv) Does not simply give the general location of the critical infrastructure.

18 C.F.R. § 388.112 exempts such information from mandatory disclosure under the Freedom of Information Act.

1. <u>The Confidential Information in the Emergency Operations Plan.</u>

The Confidential Information in the Emergency Operations Plan is treated by the Federal Energy Regulatory Commission as CEII and is exempt from public disclosure in accordance with FERC rules.[2] All of the information for which confidential treatment is requested constitutes CEII under the FERC rule.[3] The Confidential Information includes specific engineering, vulnerability, and detailed design information about existing critical infrastructure.[4] The information relates details about the production, generation, transportation, and transmission of energy, and is critical to the safety and security of the region.[5] The Confidential Information does not simply give the general location of critical infrastructure; it is information that could be useful to a person in planning an attack on critical infrastructure.[6] The Confidential Information is exempt from mandatory disclosure under 5 U.S.C. 552.

[2] 18 C.F.R. § 388.113(c).
[3] Richardson Affidavit at ¶4.
[4] *Id.*
[5] *Id.*
[6] *Id.*

Kentucky Power seeks confidential treatment of the Confidential Information in the Emergency Operations Plan for the life of the identified facilities. Once the facilities are retired the information will no longer be CEII.

B. The Identified Information is Generally Recognized As Confidential and Not Generally Known or Readily Ascertainable by Third Parties through Proper Means.

The Confidential Information in the Emergency Operations Plan is highly confidential. The Confidential Information is not available or ascertainable by other parties through normal or proper means.[7] No reasonable amount of independent research could yield this information to other parties.[8] The information reflects the internal planning efforts of AEPSC and Kentucky Power (the "Companies") and information necessary to ensure a safe and reliable management of the transmission system.[9]

Dissemination of the information for which confidential treatment is being requested is restricted by Kentucky Power, its parent, AEP, and its affiliates (including AEPSC). The Company, AEP, and its affiliates take all reasonable measures to prevent its disclosure to the public as well as persons within the Company who do not have a need for the information.[10] The Companies restrict access to the Confidential Information to those employees and representatives of the Companies who have a need to know such information due to their job and management responsibilities.[11] The Companies limit public access to buildings housing the Confidential Information by use of security guards, and persons not employed by the Companies who are allowed past security guards at buildings where Confidential Information is kept are not

[7] *Id.* at ¶6.
[8] *Id.*
[9] *Id.*
[10] *Id.* at ¶7.
[11] *Id.*

permitted to walk within such buildings without an escort.[12] The Companies' files containing the Confidential Information are maintained separately from the Companies' general records and access to those files is restricted.[13] Within the Companies, access to this information has been and will continue to be disclosed only to those employees and representatives of the Companies who have a need to know about such information due to their job and management responsibilities.[14] Outside the Companies, this information is only provided to certain persons who have a legitimate need to review the information.[15]

C. The Identified Information Is Required To Be Disclosed To An Agency.

The identified information is by the terms of the Commission's Order required to be disclosed to the Commission. The Commission is a "public agency" as that term is defined at KRS 61.870(1). Any filing should be subject to a confidentiality order and any party requesting such information should be required to enter into an appropriate confidentiality agreement.

WHEREFORE, Kentucky Power Company respectfully requests the Commission to enter an Order:

1. According confidential status to and withholding from public inspection the identified information; and

[12] *Id.*
[13] *Id.*
[14] *Id.*
[15] *Id.*

2. Granting Kentucky Power all further relief to which it may be entitled.

Respectfully submitted,

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COUNSEL FOR KENTUCKY POWER
COMPANY

Exhibit A

<u>AFFIDAVIT OF MICHAEL R. RICHARDSON</u>

Michael R. Richardson, first being duly sworn, deposes and states:

1. I am employed by American Electric Power Service Corporation ("AEPSC"). AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP) and is an affiliate of Kentucky Power Company (the "Companies"). I am responsible for support of the efficient and reliable operation and coordination of the AEP subsidiaries' transmission network in PJM and SPP; for the development of operational standards, and system studies, normal and emergency operating plans and procedures. I also assist with the development and delivery of training in support of system control center and dispatching activities and in support of operations engineering practices; with providing operational input to the transmission asset management process; with Transmission Operations compliance with all NERC and Regional Reliability Council operational and reliability requirements; with updating the annual revision and improvement of the AEP Transmission Emergency Operating Plan and ensuring the Plan conforms to the latest NERC requirements. I have also been involved in several NERC Standards Authorization Request and Standard Drafting Teams.

2. I am of the age of majority and competent to make this Affidavit. The statements in this Affidavit are based on my personal knowledge or knowledge gained through my investigation with other AEPSC and Kentucky Power employees of the matters set forth in this Affidavit.

Description of the Confidential Information for Which Protection is Sought

3. Kentucky Power is requesting that certain confidential Critical Energy Infrastructure Information ("CEII") included in Kentucky Power's Emergency Operation Plan be exempted from public disclosure pursuant to KRS 61.878(1)(k) and KRS 61.878(1)(m).

4. The Confidential Information contained in this emergency response plan (as indicated in the table below) is treated by the Federal Energy Regulatory Commission as CEII and is exempt from public disclosure in accordance with FERC rules. 18 C.F.R. § 388.113(c). All of the information for which confidential treatment is requested constitutes CEII under the FERC rule. The CEII includes specific engineering, vulnerability, and detailed design information about existing critical infrastructure. The information relates details about the production, generation, transportation, and transmission of energy. The CEII is critical to the safety and security of the region. The information does not simply give the general location of critical infrastructure; it is information that could be useful to a person in planning an attack on critical infrastructure. The CEII is exempt from mandatory disclosure under 5 U.S.C. 552.

5. More specifically, Kentucky Power seeks confidential treatment for engineering, vulnerability, and detailed design information about existing critical infrastructure related to the generation and transmission system of the AEP subsidiaries. The following table details the nature of the information and how it relates to the critical nature of the information in emergency situations.

Vol/Pg #	Confidential Information
VI/9	Description of critical points on the generation and transmission system and describes the dependent engineering relationship.
VI/10-11	Operations guide relates to the engineering and design of existing infrastructure of a specific portion of the system.
VI/12-13	Description of critical points on the generation and transmission system

Vol/Pg #	Confidential Information
	and describes the dependent engineering relationship.
VI/14-16	Load shed plan provides information regarding the vulnerability of existing infrastructure.
VI/35-36	Specific description of units equipped with a certain power stabilizer.
Appendix VII/1-6	Contact names and information of personnel involved in the emergency response operations. Public disclosure of this list would provide persons seeking to harm the generation and transmission system a list of individuals both within Kentucky Power and AEPSC and contacts at other companies who are responsible for securing the system and ensuring its continued operation and could be used to interfere with the performance of their duties.

The Information Contained in Confidential Information is Critical Energy Infrastructure Information and is Not Generally Known, Readily Ascertainable by Proper Means by Other Persons

6. The CEII is not available or ascertainable by other parties through normal or proper means. No reasonable amount of independent research could yield this information to other parties. The information reflects the internal planning efforts of AEPSC and Kentucky Power (the "Companies") and information necessary to ensure a safe and reliable management of the transmission system.

The Information is the Subject of Reasonable Efforts to Maintain Its Secrecy

7. The Confidential Information has been the subject of reasonable efforts to maintain its secrecy. The Companies restrict access to the CEII to those employees and representatives of the Companies who have a need to know such information due to their job and management responsibilities. The Companies limit public access to buildings housing the CEII by use of security guards. Persons not employed by the Companies who are allowed past security guards at buildings where Confidential Information is kept are not permitted to walk within such buildings without an escort. The Companies' files containing the Confidential Information are maintained separately from the Companies' general records and access to those files is restricted. Within the Companies, access to this information has been and will continue

to be disclosed only to those employees and representatives of the Companies who have a need to know about such information due to their job and management responsibilities. Outside the Companies, this information is only provided to certain persons who have a legitimate need to review the information.

Further the Affiant sayeth naught.

Dated: 4/27/2016

Michael R. Richardson

STATE OF OHIO)
) SS:
COUNTY OF FRANKLIN)

Michael R. Richardson appeared before me, a Notary Public in and for this County and State, and swore that the foregoing statements are true.

Nancy Spencer
Printed

Signature

My Commission Expires:

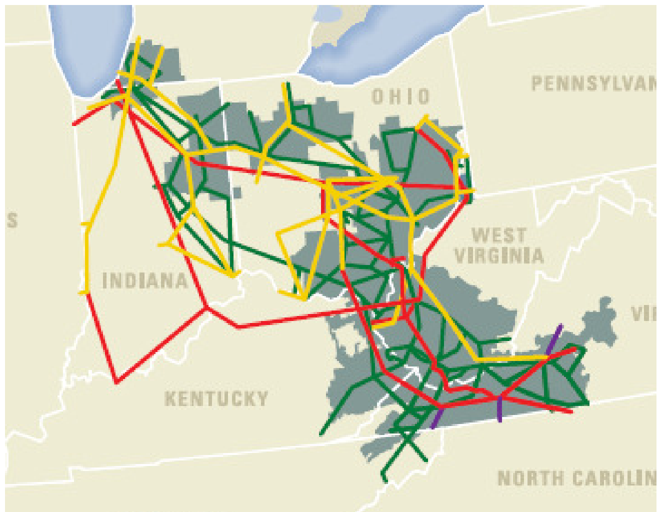
May 10, 2021

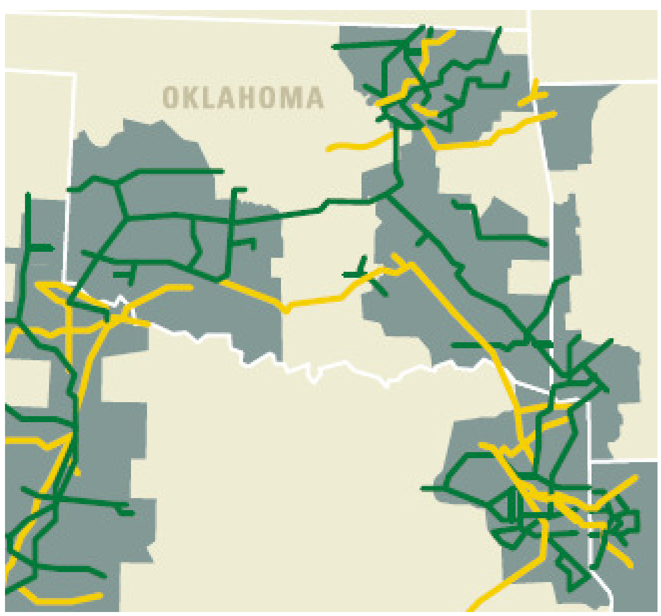
My County of Residence:

Franklin

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY





AEP East/PJM and AEP West/SPP

Emergency Operating Plan

Version 20
January, 2018

Prepared By:
Transmission Operations

AEP Confidential Special Handling

Pages have been Intentionally Removed in this document due to access restrictions for Critical Energy Infrastructure Information (CEII). You must sign and return an American Electric Power Confidentiality Agreement to receive the full document.

CONFIDENTIALITY AGREEMENT

This CONFIDENTIALITY AGREEMENT ("Agreement") is made and entered into by and between **American Electric Power Service Corporation**, a New York corporation, as agent on behalf of the operating companies of the American Electric Power system ("AEP") and ____, a(n) __________________ ___________________________ ("Recipient").

Recitals:

I. NERC Reliability Standard EOP 011 requires that the emergency plan of a Transmission Operator and Balancing Authority (referred to in this Agreement as "Emergency Plan Data") be made available to the Reliability Coordinator, as such capitalized terms are defined in the NERC Reliability Standards, for review.

II. Emergency Plan Data contains confidential and proprietary Information, including information that constitutes Critical Energy Infrastructure Information ("CEII"), as defined pursuant to 18 C.F.R. §388-113(c), and because NERC CIP Standard 003 requires the protection of information associated with Critical Cyber Assets, the availability and confidentiality of this data must be protected.

III. Within the normal course of AEP's operations and/or emergency situations, it may be necessary for AEP to share confidential system topography and station one line information with the Recipient.

IV. AEP is willing to provide such confidential information pursuant to the terms of this Agreement.

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the parties agree as follows:

1.0 Definitions.

1.1 In General. Capitalized terms used in this Agreement but not defined within this Agreement shall have the definitions contained in the NERC Glossary of Terms Used in Reliability Standards, as approved from time to time by the NERC Board of Trustees, unless otherwise stated.

1.2 "Confidential Information" means any information that is disclosed by AEP or its Representatives to the Recipient or its Representatives in connection with either Emergency Plan Data, system topography and/or station one line information, whether before or after the date hereof and irrespective of the format in which the information is provided. Emergency Plan Data shall include, but shall not be limited to, operational procedures, network topology, station one lines, or similar diagrams, CEII, incident response plans, security configuration information, generation resources, and special protection systems to support the reliable operation of the Bulk Electric System. "Confidential Information" does not include information which:

(a) is, or subsequent to disclosure becomes, part of the public domain through no fault of the Recipient;

(b) is lawfully disclosed to the Recipient by a third party without any confidentiality obligation to AEP;
(c) was in the possession of the Recipient prior to disclosure by AEP; or
(d) is lawfully and independently developed by the Recipient without use of the Confidential Information disclosed by AEP and such independent development can be demonstrated through documentation.

1.3 "Representatives" means a party's employees, officers, directors, attorneys, and agents, and its affiliates and the employees, officers, directors, attorneys, and agents thereof.

2.0 Confidentiality.

2.1 Except as provided in Article 5, Recipient hereby agrees that the Confidential Information will be kept strictly confidential during the term of this Agreement. Recipient also agrees that without the prior written consent of AEP, the Confidential Information will not be disclosed, reproduced, duplicated, copied, distributed, or in any way communicated, directly or indirectly, by the Recipient, in whole or in part, to any other party or person except as provided herein. Recipient shall use the same care in protecting the Confidential Information as it uses to protect its own confidential information, provided that Recipient shall not use less than reasonable efforts to protect the Confidential Information.

2.2 Recipient may only disclose Confidential Information to Representatives who have a need to know for the purposes of analyzing or maintaining Bulk Electric System operating reliability. However, prior to providing Confidential Information to such Representatives, the Recipient shall ensure that (i) the Representatives who are employees, officers or directors are aware of the confidentiality obligations surrounding the Confidential Information and have executed an Acknowledgment of Confidentiality Agreement ("Acknowledgment"), which is Attachment A to this Agreement, (ii) the Representatives who are agents are under obligations of confidentiality to the Recipient that are at least as restrictive as those contained herein, are aware of the confidentiality obligations surrounding the Confidential Information and have executed an Acknowledgment, and (iii) the Recipient and its Representatives will make only a limited number of copies of the Confidential Information as may be necessary in order to enable the Recipient and its Representatives to use such information for the proper purposes herein. The Recipient shall be responsible for any breach of this Agreement by any of its Representatives.

2.3 The parties recognize that the Recipient may employ or otherwise engage third-party information technology individuals ("third-party IT providers") who may have access to the Confidential Information in the normal course of their development, general maintenance, and support service activities to the Recipient. Such access for the limited purposes of performing development, maintenance, and support service activities is acceptable to the parties, provided that such third-party IT providers are under obligations of confidentiality to the Recipient that are at least as restrictive as those contained herein. The Recipient shall be responsible for any breach of this Agreement by any of its third-party IT providers.

3.0 Ownership and Use of Confidential Information.

All Confidential Information shall remain the property of AEP and/or its affiliates. No license or other rights under any patents, trademarks, copyrights or other proprietary rights is granted or implied by the disclosure of the Confidential Information. Recipient shall not use the Confidential Information for any purpose other than for analyzing or maintaining bulk electric system operating reliability.

4.0 Disposition of Confidential Information.

4.1 The Recipient, upon written request from AEP, shall promptly return or destroy all Confidential Information in its possession. If requested by AEP, Recipient shall provide AEP with a certificate that all Confidential Information has been returned or destroyed. The return or destruction of the Confidential Information shall not extinguish any rights or obligations hereunder with respect to the Confidential Information.

5.0 Legally Required Disclosures and Emergencies.

5.1 The Recipient will exercise all reasonable efforts against the compelled disclosure of Confidential Information to any party who is not a signatory to this Agreement. In the event disclosure of Confidential Information is sought from a Recipient by judicial or regulatory order or directive, the Recipient shall provide timely notice to AEP and furnish all reasonable assistance required by AEP in protecting the confidential nature of the Confidential Information for which disclosure is sought.

5.2 Notwithstanding any other provisions herein, in emergency circumstances that could jeopardize operating reliability, a Recipient may take whatever steps are necessary to maintain system operating reliability. The Recipient must report to its reliability coordinator each emergency that resulted in any deviation from this Agreement within 24 hours of such deviation.

6.0 Term and Termination.

6.1 The term of this Agreement shall commence immediately upon the signatures of both parties hereto and shall remain in effect until terminated.

6.2 Any party wishing to terminating this Agreement as to that party shall notify the other party in writing of its desire to terminate this Agreement. Termination shall be effective 30 days following acknowledgement of receipt of such written notice. Upon such termination, that party will be prohibited from further receipt of Confidential Information.

6.3 Termination does not excuse the Recipient from holding confidential any Confidential Information received during the term of this Agreement.

7.0 No Warranties; Limitation of Liability.

7.1 AEP makes no representations or warranties whatsoever with respect to the availability, timeliness, accuracy, reliability, or suitability of any Confidential Information pursuant to this Agreement. Recipient assumes any and all risk and responsibility for use of, and reliance on, any Confidential Information. AEP shall not be subject to any liability to the Recipient based on the Recipient's use of the Confidential Information. In no event shall AEP be liable to Recipient for any incidental, indirect, special, punitive or consequential damages (including without limitation damages for lost profits).

7.2 Recipient disclaims and waives all rights and remedies that it may otherwise have with respect to all warranties and liabilities of AEP, expressed or implied, arising by law or otherwise, with respect to any faults, errors, defects, inaccuracies or omissions in, or availability, timeliness, reliability, or suitability of the Confidential Information.

8.0 Governmental Authority.

This Agreement is subject to the laws, rules, regulations, orders, and other requirements, now or hereafter in effect, of all regulatory authorities having jurisdiction over the Confidential Information, this Agreement, AEP, and Recipient. All laws, ordinances, rules, regulations, orders, and other requirements, now or hereafter in effect, of governmental authorities that are required to be incorporated in agreements of this character are by this reference incorporated in this Agreement.

9.0 Remedies.

Recipient acknowledges that improper or unauthorized use or disclosure of Confidential Information could cause irreparable harm to AEP and that monetary damages would not be an adequate remedy for a breach of this Agreement. In the event of any breach or threatened breach of this Agreement, AEP shall be entitled to pursue injunctive and other equitable relief, and Recipient agrees to waive any requirement for the posting of a bond in connection with such remedy and any defense that AEP may have an adequate remedy at law. Such injunctive and equitable relief shall not be deemed to be the exclusive remedy for a breach of this Agreement, but shall be in addition to all other available remedies.

10.0 General.

10.1 Governing Law. This Agreement shall in all respects be interpreted, construed, and enforced in accordance with the laws of the State of New York, without reference to rules governing conflicts of law, except to the extent such laws may be preempted by the laws of the United States of America, Canada, or Mexico, as applicable.

10.2 Entire Agreement. This Agreement constitutes the entire agreement of the parties with regard to Confidential Information disclosed by AEP to Recipient.

10.3 Assignability. This Agreement may not be assigned by either party without the prior written consent of the other party, provided that AEP may assign the Agreement to one of its affiliated companies without the prior written consent of Recipient.

10.4 Severability. All provisions of this Agreement are severable, and the unenforceability of any of the provisions of this Agreement shall not affect the validity or enforceability of the remaining provisions of this Agreement

10.5 No Waiver. Failure of either party to insist upon strict performance of any of the terms and conditions shall not be deemed to be a waiver of those terms and conditions.

10.6 Counterparts and Faxed Signatures. This Agreement may be executed in counterparts, and in the absence of an original signature, faxed signatures will be considered the equivalent of an original signature.

10.7 Notices. Notices shall be in writing and shall be sent to the addresses listed below, either by personal delivery, by the U.S. Mail, overnight mail, fax or other similar means. All notices shall be effective upon receipt.

[Signature page follows]

IN WITNESS WHEREOF, the duly authorized Representatives of the parties hereto have executed this Agreement as of the date indicated below and this Agreement shall be effective upon the signature of both parties.

AEP	**RECIPIENT**
By:______________________________	By:______________________________
Name:____________________________	Name:____________________________
Title:____________________________	Title:____________________________
Date:____________________________	Date:____________________________
Address:	Address:
American Electric Power Service Corporation	________________________________
8400 Smith's Mill Road	________________________________
New Albany, OH 43054	________________________________
Attention: Rosalyn N McAuley	________________________________
Operations Engineering Manager	________________________________
Telephone: 614-413-2385	Telephone:______________________
Facsimile: 614-413-2653	Facsimile:_______________________

[Confidentiality Agreement signature page]

Attachment A

Acknowledgment of Confidentiality Agreement

I, ____, hereby acknowledge having read and understood the terms of the attached Confidentiality Agreement and agree to treat all Confidential Information pursuant to that Confidentiality Agreement in strict conformance with the terms thereof.

Signature:______________________________

Printed:________________________________

Company:______________________________

Date:__________________________________

Document Control

Preparation

ACTION	NAME(S)	TITLE
Prepared by:	Michael Richardson	Principal Engineer
Reviewed by:	TOPS Engineering	Transmission Operations Engineering Staff

Approvals

Transmission Operations Business Unit

Name: Rosalyn McAuley **Signature:**

Title: Manager, Transmission Operations Engineering **Date:**

Review Cycle

Quarterly	Semi-annual	Annual √	As Needed √

Retention Period

Six months	One Year	Two Years	Three Years √

Release History

VERSION	DATE	FILE NAME	CHANGE NOTICE
Version 1.0	June, 1999	EOP_V1.pdf	Annual Review
Version 2.0	February, 2001	EOP_V2.pdf	Annual Review
Version 3.0	May, 2001	EOP_V3.pdf	Annual Review
Version 3.1	June, 2001	EOP_V3_1.pdf	Minor Revisions
Version 4.0	June, 2002	EOP_V4.pdf	Annual Review
Version 5.0	June, 2003	EOP_V5.pdf	Annual Review
Version 6.0	March, 2004	EOP_V6.pdf	Annual Review
Version 7.0	October, 2004	EOP_V7.pdf	Major Revisions
Version 8.0	June, 2005	EOP_V8.pdf	Annual Review
Version 9.0	February, 2006	EOP_V9.pdf	Annual Review
Version 9.1	March, 2006	EOP_V9_1.pdf	Minor revisions

Version 9.2	April, 2006	EOP_V9_2.pdf	Minor revisions
Version 9.3	September, 2006	EOP_V9_3.pdf	Minor revisions
Version 10.0	March, 2007	EOP_V10.pdf	Annual Review
Version 10.1	May, 2007	EOP_V10_1.pdf	1. Updated Implementation with some revised names and corrected some phone numbers. 2. Updated the following Sections based on recommendations from the NERC Readiness and RFC audit teams. Section I, II, III, V, VIII, X
Version 11.0	April, 2008	EOP_V11.pdf	Annual Review
Version 11.1	August, 2008	EOP_V11_1.pdf	Minor edits, and classification of document as AEP Confidential Special Handling
Version 12.0	April, 2009	EOP_V12.pdf	Annual Review
Version 12.1	August, 2009	EOP_V12_1.pdf	Added Document Control, updated Section VI-Rockport SPS and Section VIII-Black Start test dates
Version 12.2	September, 2009	EOP_V12_2.pdf	Updated Implementation phone numbers Updated Section VIII-Black Start - AEPW/SPP test dates and backup agreement with METC for Cook Updated Appendix VII Emergency Contact phone numbers
Version 13.0	April, 2010	EOP_V13.pdf	Annual Review • Implementation names/phone numbers • Section III - Capacity Deficiency Program consistent with PJM • Section V - Fuel Limitations added reference to SPP Criteria, update Figure V-1 • Section VI - Transmission

			Emergency Procedures SPS, UVLS, PJM procedures, PSS updates • Section IX -DOE and NERC Reporting clarified reporting times • Section X – Emergency Communications phone numbers • Section XI – Training hours • Appendix III – Under Frequency Guidelines • Appendix V – Manual Load Shedding Guidelines loads • Appendix VII Emergency Contact phone numbers
Version 13.1	December 2010	EOP_V13_1.pdf	Updated 1.) Section III Capacity Deficiency Program • Minor edits to PJM portion 2.) Section VI Transmission Emergency Procedures • Indiana – Rockport Plant Special Protection System 3.) Section VIII System Restoration • Unit Test dates • TDC Name changes • System Restoration dB 4.) Appendix VII • AEP internal contacts due to reorganization
Version 14.0	June 2011	EOP_V14.pdf	Annual Review
Version 15.0	June 2012	EOP_V15.pdf	Annual Review / Correct Date typo
Version 15.1	December 2012	EOP_V15_1.pdf	Update Section III – Load updates Section VI – Load shedding updates Section VIII – ALR test dates updates Restoration frequency range update

			Section IX – NERC form update Section X – Satellite phone # update Appendix VI – Added PER-003-1 Appendix VII – Added new contact
Version 16.0	August 2013	EOP_V16.pdf	Annual Review Section III – Update PJM and SPP sections to be consistent with respective RC requirements Section V – Update reference to NERC standards, PJM manuals, and SPP Criteria. Section VI – Updated PJM manual references SPP Criteria references. SPP IROL Relief Guide dated 06/28/13 Rockport Operating Procedure Columbus Southern Under Voltage Load Shed Scheme Added Plant Fault Duty Procedures Operating in an Unknown State Section VIII – This section contains highlights of the AEP System Restoration Plans approved by PJM and SPP RC. Refer to the approved plans on TOps Sharepoint for additional information. Section IX – Update NERC fax #, email address, and links to NERC's reorganized web site.

			Section X – Update NERC, PJM manual references, TDC communication references. Section XI – Update System Operator Training objectives
Version 17.0	September 2014	EOP_V17.pdf	Annual review Section III – Update PJM and SPP sections to be consistent with respective RC requirements Section V – Update SPP section to be consistent with SPP Emergency Operating Plan Section VI – Update to reflect AEP / PJM / SPP Emergency Procedures Section VIII - This section contains highlights of the AEP System Restoration Plans approved by PJM and SPP RC. Refer to the approved plans on TOps Sharepoint for additional information. Section IX – Updated to be consistent with AEP Reporting Operating Plan. Sorted Attachment 1 table by reporting time. Appendix II – Updated high voltage limits in Table AIII-4 to reflect Mike Skidmore's recommendations. Appendix III – Updated AEP East, PSO, SWEPCO peak load

			tables. Appendix IV – Update load relief number Appendix V – Update Tables AV-1, AV-2, PSO, and SWEPCO tables Appendix VI – Added NERC IRO-001-1.1 R8 and IRO-004-2 R1 Appendix VII – Updated contact list and associated phone numbers
Version 18.0	November, 2015	EOP_V18.pdf	Annual Review Implementation – Update contact information Section III – Update PJM and SPP sections to be consistent with respective RC requirements. Updated load management, unit retirements. Section IV – Updated to reflect unit retirements. Section V – Updated to reflect changes in PJM and SPP requirements. Section VI – Updated to reflect changes in PJM m03, m13, m14, m37, and SPP Emergency Operating Plan. Emergency Actions dealing with voltage control. PCLLRW and PCAP additions. Updated UVLS schemes

			Updated Plant Fault Duty Procedures. Section VII – Updated to align with the AEP Emergency Response Plan. SectionVIII – Refers the reader to the Reliability Coordinator approved system restoration plan for the PJM / SPP areas. Section X – Updated to reflect NERC COM standard, PJM M01, and SPP Criteria 10 changes. Updated phone numbers. Section XI – Updated to reflect NERC PER-005 requirements. Appendix V – Updated load shed MW. Appendix VI – Incorporates updated AEP Operator to Act Policy document. Appendix VII – Updated internal / external contacts
Version 19.0	November, 2016	EOP_V19.pdf	Annual Review Updated contacts in Implementation section

			Section II – Updated policies and guidelines by referencing Appendix VI AEP's Operator Authority to Act Policy Section III – Updated to line up with PJM and SPP BA plans. Section VI – Updated to reflect PJM / SPP manual updates, AEP procedure updates, and NERC standards. Section IX – Event Reporting Operating Plan updated Section X – Updated to reflect PJM / SPP manual updates, and NERC COM 001-2.1. Appendix V – Updated load shed MW. Appendix VI – Incorporates updated AEP Operator to Act Policy document. Appendix VII – Updated internal / external contacts
Version 20.0		EOP_V20.pdf	Annual Review Implementation Section- Updated contacts Section II- Updated policies to reflect updates in NERC Standards Section III- Streamlined by referencing the PJM/SPP detailed capacity deficiency procedures. Kept the table highlighting AEP's response to the RC requests. Removed the EEA description which is in the

			NERC standards. Section IV – Abnormal Frequency Removed Gavin Section V – Fuel TOP is not responsible for fuel per NERC EOP 011. Section VI –Transmission Emergency Procedures Updated to reflect PJM / SPP manual references, AEP procedure updates, and NERC standards. Section VIII – References AEP Restoration Plans approved by the Reliability Coordinators Section IX – Incorporated AEP Event Reporting rev5 document. Section X –Emergency Communications Updated PJM /SPP manual references, AEP satellite phones Section XI – Updated training requirements. Appendix V – Updated load shed MW. Screen dumps of AEP East ADX Appendix VII – Updated internal / external contacts

Purpose

If the AEP/PJM footprint or AEP/SPP footprint experiences a Capacity Deficiency which requires implementation of our Capacity Deficiency plan or if a portion of the PJM or SPP region experiences a wide-spread area outage or becomes separated from the interconnected system, the System Control Center (SCC) and/or Commercial Operations – Market Operations (MO)) will contact their Executive Team representative listed below, explain the system emergency, and begin to take actions to implement the Emergency Operating Plan (EOP).

PJM is the Balancing Authority for AEP East/PJM while SPP BA is the Balancing Authority for AEP West/SPP. The following procedures offer clarification on Section III (Capacity Deficiency) of our plan.

Procedure for implementation of Section III: Capacity Deficiency of the Emergency Operating Plan (EOP):

For the AEP/PJM footprint, PJM is responsible for monitoring the operation of the PJM RTO and declaring the existence of a capacity deficiency, and for directing the operations of the PJM Members as necessary to manage, alleviate, or end a capacity emergency.

For the AEP/SPP footprint the SPP BA is responsible for declaring and communicating the existence of emergencies related to energy and capacity shortages, and for directing the operations of the appropriate entities within the SPP Balancing Authority Area (BAA) as necessary to manage, alleviate, or end an energy or capacity emergency.

Whenever PJM declares a generation alert/warning/action for the AEP/PJM footprint, the System Control Center will contact their Executive Team representative and the Market Operations which will be responsible for notifying their Executive Team representative.

Whenever SPP declares an emergency related to energy and capacity shortages for the AEP/SPP footprint, the System Control Center will contact their Executive Team representative and the Market Operations which will be responsible for notifying their Executive Team representative.

PJM / SPP BA will make the decision as to when to implement the provisions of EOP Section III: Capacity Deficiency and the SCC will make notifications as required.

Executive Team

Transmission -	Robert W. Bradish, [redacted]
	Allan W Smith, [redacted]
Regulated Commercial Operations – Market Ops & Fuels	
	Jeff LaFleur [redacted]
Energy Supply (competitive)-	Charles E. Zebula [redacted]
Generation –	Mark C McCullough [redacted]
AEP Utilities -	AEP Utilities East: [redacted]
	AEP Utilities West: [redacted]
Corporate Communication -	Dale E Heydlauff [redacted]
Customer Solutions Center -	Robert L Cheripko [redacted]
Environmental Services -	John McManus [redacted]

The Management Group personnel listed below will be responsible for keeping the Executive Team informed and up to date as well as keeping their organizations informed of all the actions taking place. From previous operating experience it would be beneficial for Transmission Operations and Corporate Communications be coordinated from the System Control Center (SCC) location. The other parties could either operate in the SCC or coordinate their efforts by telephone and/or 800 MHz radios.

In an emergency situation, the FERC rules allow for temporary suspension of the affiliate restrictions and standards of conduct in order to preserve the reliability of the grid. A notice will be posted on the OASIS that states: "AEP is in an emergency situation and the separation between the Transmission Reliability and Market functions has been temporarily suspended."

The OASIS posting is on the AEP FERC Standards of Conduct for Transmission Providers. (www.aep.com under About Us/ Required Internet Postings) Ethics and Compliance would coordinate the postings from Transmission. (8-200-6226 or 614-716-6226)

Management Group

Group responsible for directing operational implementations of EOP:

Transmission Operations -	David Ball [redacted]
	Roz McAuley [redacted]
Regulated Market Operations -	
	William R Thompson [redacted]
	Tom Presthus [redacted]
Environmental Services -	John McManus [redacted]
Generation -	
	Julie Sherwood [redacted]
	Daniel V Lee [redacted]
	Paul W Franklin [redacted]
Regulated Commercial Operations - Fuels	Marguerite C Mills [redacted]
Distribution -	Thomas L Kirkpatrick [redacted]
Corporate Communication -	Melissa A McHenry [redacted]
	Rachel Hammer [redacted]
Customer Solutions Center -	Bradley A Galford [redacted]
Customer Services -	Don Nichols [redacted]
Workplace Services -	Mike Roman [redacted]
	Jerry L Waller [redacted]
	Derek L Lindeman [redacted]
	Glenda L Staley [redacted]
Regulatory Services -	Andrew J Williamson [redacted]
	Andrea E Moore [redacted]
	Steven H Ferguson [redacted]
	Will Castle [redacted]
	Ranie Wohnhas [redacted]
	Thomas Brice [redacted]
	[redacted]
	Emily C Shuart [redacted]
	Ron K. Ford [redacted]

The Management Group above will provide guidance to the System Control Center regarding implementation of provisions of the Emergency Operating Plan (EOP), but the final decision resides with the System Control Center Operator as per NERC Standards and NERC Certification requirements. The Management Group will also assist in external communication to such agencies as the Public Utilities Commissions, Media Outlets, Homeland Security, State Emergency Management Centers, Nuclear Regulatory Commission (NRC), Department of Energy (DOE), etc.

Table of Contents

Section I
Introduction

This plan is aimed at maintaining reliable power system operation associated with the bulk power supply system. The main focus is on preventing major power outages of wide extent involving generating plants, transmission lines and bulk power substations that collectively furnish the power to major points of distribution.

While localized power interruptions are considered beyond the scope of this plan, it is important to recognize that some of the plan's features will be of benefit in those situations.

The Emergency Operating Plan (EOP), as outlined in this report, is primarily directed toward providing concepts, recommendations for facilities (communications, displays, alarms, etc.) and basic data which, together with trained personnel, will permit a sound approach to the handling of any emergency situation that may arise. This keeps the plan dynamic and also avoids the impractical approach of trying to define every condition that may arise.

Should conditions arise that are beyond any reasonable expectations, including multiple outages caused by either weather or equipment failures, refer to the NERC Reliability Coordinator approved System Restoration Plans. The System Restoration Plan contains general procedures for restoring the system as quickly as possible. Every effort will be made to avoid the need to use restoration procedures.

DOE form OE-417, which is mandatory pursuant to Section 13(b) of the Federal Energy Administration Act of 1974 (Public Law 93-275), places an added emphasis on the need for formal procedures to be followed in emergencies related to the bulk power system. Reporting procedures related to this form are summarized in Section IX.

Personnel receiving copies of this plan need to become familiar with its contents; furthermore, all employees who would be involved in the various procedures need to have sufficient training to perform the intended tasks. It is intended that the procedures set forth in this plan will be followed in the sequence, and for the reasons, listed. However, due to the dynamic nature of a power delivery system and the unknowns that can accompany certain events, it may become necessary at times to deviate from the standards herein.

AEP considers all elements of EOP-011, EOP-005-2, PJM Manuals, SPP Criteria, SPP Reliability Coordinator Area Restoration Plan, and SPP BA Emergency Operations Plan in the development of AEP's Emergency Operating Plans.

AEP will supply the AEP Emergency Operating Plan to neighboring entities. Information that is designated as FERC Critical Energy Infrastructure Information (CEII) will be removed from the Plan unless a signed confidentiality agreement is returned by the neighboring entity.

This plan will be updated annually. In accordance with NERC EOP-011 R1, AEP will submit the plan(s) to the Reliability Coordinator for review.

Section 7 of PJM Manual 13 states the plan(s) need to be submitted to PJM Reliability Coordinator using the email address dispsup@pjm.com.

SPP requires the plan(s) to be submitted to the SPP Reliability Coordinator using the email address EmerOpPlans@spp.org.

Section II

Policies and Guidelines

Power systems must be operated within limits that will ensure adequate generation and transmission capacity to avoid cascading. While power system load grows more or less on a continual basis, transmission and generation equipment is added in finite blocks. This results in operating margins that not only are changing, but may result in constraints that alternate in severity both in generation and transmission.

In developing a set of operating limits for the AEP System, it is important to do so within a general framework in order to ensure that the operating objectives are met. Accordingly, a set of general guidelines is presented below.

1. First and foremost, in carrying out these emergency procedures, our Environment, Safety & Health Philosophy is:

   "No aspect of operations is more important than the health and safety of people. Our customers' needs are met in harmony with environmental protection."

2. Each Transmission Operator has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies, including the shedding of firm load.
3. The integrity of the transmission system will be maintained at all times without planned internal separation. Actual thermal overloads or voltage constraints must be alleviated immediately using identified transmission procedures.
4. Responsibilities and Authorities of AEP Transmission System Control Center Reliability Coordinators and Transmission Dispatchers in performing various actions to alleviate operating Emergencies and / or ensure stable and reliable operation of the AEP transmission system are outlined in AEP's Operator Responsibility and Authority to Act policy (Refer to Appendix VI). In general, all Operating Instructions issued, as outlined in the policy, shall be complied with unless such actions cannot be physically implemented or would violate safety, equipment, regulatory or statutory requirements. Maximum reasonable assistance will be given to adjacent systems experiencing difficulty. However, such assistance will be terminated, without opening interconnection circuits if possible, when the reliable operation of the AEP System is impaired. This also assumes the following:
   a. Requesting TOP has implemented its comparable Emergency procedures
   b. Request is consistent with AEP's Operator Authority to Act Policy as shown in Appendix VI.
5. The AEP System should be operated so that the occurrence of any single contingency (circuit, transformer, or unit) will not result in instability, uncontrolled separation, or Cascading outages that adversely impact the reliability

of the Interconnection. The single contingency analysis is geared to the current state of the System which reflects maintenance and forced outage events as they occur. Operating Plans shall be developed to ensure prompt action to prevent or mitigate identified adverse System impactsOperation of the AEP System should also take into consideration effects on facilities outside of the AEP System. Other systems should be advised of known conditions that may present a hazard to their operation or could result in an Emergency. Events and conditions affecting regional or national bulk power supply reliability must be reported to the U.S. Department of Energy (DOE) and NERC.

6. The principles of sound interconnected operation will be maintained when the AEP System experiences a generation load unbalance by following Operating Instructions issued by the applicable Balancing Authority unless it can not be physically implemented or it would violate safety , equipment, regulatory, or statutory requirements.
7. Generating plant, substation, and transmission equipment maintenance and testing should be held to a minimum prior to and during System Emergency conditions. When such conditions are expected to exist, the System Control Center (SCC) will notify each Transmission Dispatching Center (TDC) and Market Operations (MO), so that work that could jeopardize generation or transmission capabilities can be postponed.
8. The System Control Center Operator (SCCO) shall notify the Reliability Coordinator of current and projected conditions when experiencing an operating emergency.
9. Some typical acronyms used throughout this plan are:

SCC	AEP System Control Center, New Albany
TDC	Transmission Dispatching Center
	Columbus West
	Columbus East
	Columbus Central
	Roanoke North
	Roanoke South
	Tulsa
	Shreveport
	Corpus Christi
DDC	Distribution Dispatching Center
CC	Corporate Communications
CSC	Customer Solutions Center
MO	Market Operations
RF	Reliability First
SPP	Southwest Power Pool
LCC	Local Control Center (synonymous with SCC)
LSE	Load Serving Entity
FEL	Fuel, Emissions and Logistics

Section III

Capacity Deficiency Program

Purpose

Provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power AEP East/PJM and AEP West/SPP Systems in the event of a capacity deficiency.

Criteria

The goals of AEP are to safely and reliably operate the interconnected network in order to avoid widespread system outages as a consequence of a major disturbance. Precautionary procedures including maintaining Daily Operating Reserves, as specified in Reliability First Standard BAL-002-RFC-02, SPP Emergency Operating Plan and PJM Manual M13, will assist in avoiding serious emergency conditions such as system separation and operation at abnormal frequency. BAL-502-RFC-02 establishes common criteria, based on “one day in ten year” loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the Reliability First Corporation (RFC) region.
However, adequate Daily Operating Reserves cannot always be maintained, so the use of additional emergency measures may be required. A Capacity Deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements. In the event that a report needs to be filed with the Department of Energy (DOE), NERC, or a Reliability Coordinator, the Transmission Operations Engineering group can assist in preparing those reports.

EOP 011-1 requires the Balancing Authority to have an emergency plan to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. PJM and SPP are the registered Balancing Authorities in the AEP East and AEP West areas.

AEP West/SPP Procedures

AEP will follow request from the SPP BA as described in the SPP BA Emergency Operating Plan. There are four Reserve Zones in the SPP Balancing Authority Area. (SPP BAA) AEP is part of SPP Reserve Zone #4 starting March 1, 2014.

Note: The following section contains excerpts from Section VI – Capacity and/or Emergencies of the SPP Emergency Operating Plan dated September 5, 2017. SPP maintains the current complete version of the SPP Emergency Operating Plan on SPP OPS1.

Responsibility

The SPP BA is responsible for declaring and communicating the existence of emergencies related to energy and capacity shortages, and for directing the operations of the Stakeholders within the SPP BAA as necessary to manage, alleviate, or end an Energy or Capacity Emergency. SPP is responsible for balancing energy and load to resolve a Capacity Emergency. SPP BA utilizes the SPP RSG and any executed agreements with neighboring Balancing Authorities for the mutual provision of service to meet a Capacity and/or Energy Emergency. If an Energy or Capacity Emergency is recognized in the SPP BAA, the BA will request the SPP RC to issue the appropriate level EEA Alert to notify neighboring entities of the Energy situation in the SPP BAA.

If the SPP BAA is energy deficient, Stakeholders will jointly implement emergency procedures up to the point of a manual load shed. If manual load shed is necessary, SPP will determine how much each Participating Entity will shed and communicate this information by issuing Operating Instructions to the appropriate Participating Entity in accordance with the SPP Communications Protocols and COM-002.

If the SPP BAA is deficient, it will only use the assistance provided by the Eastern Interconnection frequency bias for the time needed to implement corrective actions. The SPP BA shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Transaction changes.

Section VI of the Capacity and / or Energy Emergencies of the SPP BA Emergency Operating Plan is summarized in Table III-1 below. The Communications are the anticipated communications paths initiated by SPP BA[1] to AEP as an “impacted entity.

	Activity	Communications	Description		Reference
	Communications	SPP BA – AEP	SPP communications listed below will use their Communication Protocols which may include VOIP telephone, blast call, cell phones, or satellite phone		**4.7**[1]
	Stakeholder Communications	AEP – SPP	Communicate with SPP using telephone, email, CROW, ICCP, Market UI/API as applicable		**4.7.1**[1]
	Maximum Emergency Generation Alert	SPP BA-MO SPP BA-SCC SCC-TDC	**SPP** Day Ahead commitment study indicates Resources not intended for economic commitment are needed to ensure system reliability. **SCC to Notify_TOPS West email notifications**		6.2.1[1]
	Energy Emergency Alert 1	SPP BA-MO	**SPP BA determines if any generator outages are available for postponement. SPP BA verifies the times for potential postponement with the generator owner.** **SPP BA utilizes maximum Emergency Operating Limits of online resources.**		6.3.1[1]
		SPP BA-SCC SCC-TDC	SPP BA determines what if any pertinent transmission outages can be recalled, and verifies recall times with transmission owners.		6.3.1[1]
		SPP BA-MO	SPP may ask MO if units are contrained due to environmental reasons. MO notifies SPP BA of any AEP units constrained due to environmental issues.		5.3
		SPP BA –SCC SPP BA –MO	SPP BA notifies SCC / MO it will request an EEA1 **SCC to Notify_TOPS West email notifications**	**EEA 1**	6.3.1
		SPP BA –MO	**SPP BA identifies available resources that are needed for capacity. MO** to start up all available resources requested.		

	Activity	Communications	Description		Reference
		SCC – TDC/Corporate Communications	**SCC** issue **Voluntary Load Curtailment Alert** to TDC and Corporate Communications.	**EEA 1**	EEA 1, step 7[2]
	Energy Emergency Alert 2	**SPP BA – MO** **SPP BA – SCC**	**SPP BA will make timely notifications to SCC and MO when requesting an EEA 2,** **SCC to Notify_TOPS West email notifications**	**EEA 2**	**6.3.2[1]** **(ORW EOP v16)**
		SPP BA –MO	**MO** commit all quick start generation resources as requested by SPP BA SPP BA may dispatch resources to Maximum Emergency Operating Limit.		
		SPP BA –SCC SCC-TDC	**SCC/TDC** recall transmission outages identified in EEA 1 process.		
	Maximizing Generator Output and Availability	SPP BA – MO	**MO** defer or cancel planned generator outages requested by SPP BA **MO** maximize generator output requested by SPP BA	**EEA 2**	6.3.2.1[1] 6.3.2 (ORW EOP v16)
	Non firm load curtailment	SPP BA – SCC, SPP BA – Corporate Communications , SPP BA – MO SCC – AEP Regulatory Services	SPP alert members on Public Appeals, Voltage Reduction, and Interruptible Load as listed below **Regulatory Services** contact Government Agencies to reduce their use of electricity	**EEA 2**	6.3.2.2[1]
	Public Appeals	SPP BA-SCC SCC-TDC SCC - AEP Corporate Communications	**TDC** **Execute Voluntary Load Curtailment** when requested by SCC **Corporate Communications** implement public appeal plan **SCC to Notify_TOPS West email notifications** **SCC** prepares DOE report	**EEA 2**	6.3.2.2.1[1] (Step 8 EOP v16)
	Voltage Reduction	SPP BA-SCC	Voltage Reduction – N/A AEP West SPP does not have any voltage reduction capabilities	**EEA 2**	6.3.2.2.2[1] (Step 7 EOP v16)

	Activity	Communications	Description		Reference
	Interruptible / Curtailable Loads	SPP BA-SCC SPP BA-MO SCC-TDC TDC-DSM Coordinator	**SPP BA** provide time, duration, and MW to SCC **TDC** initiates curtailment of interruptible loads **DSM Coordinator** implement **Demand-Side Management** **MO** implement curtailment generation plant use **TDC** implement curtailment non-Essential building load **TDC** implement SWEPCO/SPP ERCOT Load Transfer	**EEA 2**	6.3.2.2.3[1] (Step 6 & 10 EOP v16) 5.4
	Appeals to Customers to Use Alternate Fuels	SPP BA –SCC SCC-TDC	TDC make appeals to customers with generators to utilize alternate fuels not in short supply. SCC issue **Mandatory Load Curtailment Alert** to TDC **SCC to Notify_TOPS West email notifications**	**EEA 2**	6.3.2.3[1] (Section V EOP v16)
	Miscellaneous	SPP BA-SCC SCC-TDC	Prepare for potential load shedding. **SPP BA** provide forecasted MW amount. **SCC** will issue a **Mandatory Load Curtailment Warning** to TDC. **SCC to Notify_TOPS West email notifications**	**EEA 2**	6.3.2.4[1] EEA 2[2],step 7 (Step 11 EOP v16)
	Energy Emergency Alert 3	SPP BA –SPP RC	**SPP BA notifies SCC/MO it will requrest an EEA3** **SCC to Notify_TOPS West email notifications**	**EEA 3**	6.3.3[1]
	Firm Load Shed	SPP BA-SCC SCC-TDC	**SPP BA** provide updates on load shedding MW amount and the area if appropriate. **SPP BA** issue instruction to shed load **SCC** issue the order **Execute Mandatory Load Curtailment** **SCC** prepares DOE report **SCC to Notify_TOPS West email notifications**	**EEA 3**	6.3.3.1[1] 6.4.[1] EEA 3[2], steps 3, 4 (Step 13 EOP v16)
	Monitoring Energy Emergency Alert Level		**SPP BA reviews status of EEA hourly.**		6.3.3.2

	Activity	Communications	Description		Reference
	Manual Load Shed for CPS and DCS Deviation	SPP BA –SCC SCC-TDC	**SPP BA notify SCC to Manually shed firm load without delay.** **SCC issue order <u>Execute Mandatory Load Curtailment</u>** **SCC prepare DOE report.** **SCC to Notify_TOPS West email notifications**		6.4
	Forecast Mininum Generation Alert	SPP BA-MO SPP BA-SCC SCC-TDC	**SPP** informs Members SPP foresees need to operate resources below Minimum Emergency Capacity Operating Limit to maintain system reliability for Operating Day. **SCC to Notify_TOPS West email notifications**		6.5

Table III-1 Capacity Deficiency Summary – AEP/SPP

References:

1. **SPP Emergency Operating Plan Version 6**
2. **SPP Ops: Energy Emergency Alerts Version 1.4**
3. **AEP Emergency Operating Plan v16, plan used prior to SPP Balancing Authority**

AEP East/PJM Procedures

(note: the following section contains excerpts from PJM Manual – M13 Revision 65. PJM maintains the complete current version of M13 on the PJM web site PJM.COM.

Overview

PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM Members as necessary to manage, allocate, or alleviate an emergency.

• *PJM RTO Reserve Deficiencies* — If PJM determines that PJM-scheduled resources available for an Operating Day in combination with Capacity Resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the PJM RTO, PJM performs the following actions:

• Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.

• Purchases capacity or energy from resources outside the Control Area. PJM uses its best efforts to purchase capacity or energy at the lowest prices available at the time such capacity or energy is needed. The price of any such capacity or energy is eligible to determine Locational Marginal Prices in the PJM Energy Market. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for Operating Agreement Accounting (M28)..

In this section, the AEP System Control Center will be referred to as SCC and the AEP Market Operations will be referred to as MO.

Addendum to Manual Load Dump Procedures

AEP understands that PJM intends to implement these curtailment protocols consistent with the agreements that PJM entered into in Kentucky and Virginia, in Stipulations approved by the Kentucky Public Service Commission and Virginia State Corporation Commission (with modifications) in Case No. 2002-00475 and Case No. PUE-2000-00550, respectively.

Capacity Deficiency Summary Table

A summary of section 2 of the PJM Manual 13 Capacity Emergencies, together with the typical sequence and the method of communication, are presented in the following Table III-2.

		Communications	Description		Time Estimate
Alerts	Unit Startup Notification Alert	PJM-MO PJM-SCC SCC-TDC	SCC/MO notify management SCC issue Notify PJM_Emer_Procedures email notification TDC advise station MO orders units to be in a state of readiness		
	Maximum Generation Emergency / Load Management Alert	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC	SCC/MO review scheduled or actual maintenance / testing of transmission / generation affecting capacity or critical transmission to determine if it can be deferred or cancelled MO report any fuel / environmental issues to PJM SCC/MO notifies Transmission/MO management of the alert. SCC issue Notify PJM_Emer_Procedures email notification	**EEA 1**	< 1 hr.
	Primary Reserve Alert	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC SCC-MO	SCC/MO notifies Transmission/MO management of the alert. SCC issue Notify PJM_Emer_Procedures email notification SCC/MO reviews plans to determine if any maintenance or testing, scheduled or being performed, on any generating equipment or critical monitoring, control, or bulk power transmission facility can be deferred or cancelled. SCC request MO to evaluate the impact of current environmental constraints and start the process to possibly lift those constraints identified. MO inform PJM of any environmentally restricted units		< 1hr.
	Voltage Reduction Alert	PJM-SCC via All-Call SCC-TDC	AEP does not have a voltage reduction program SCC issue Notify PJM_Emer_Procedures email notification		< 1 hr.; however, alert needs to be issued day ahead
Warnings & Action Items					
Step 1	Pre-Emergency Load Management Reductions (30,60, or 120 minute)	PJM-SCC via All-Call PJM - MO	Member Curtailment Service Providers implement load management reductions as requested by PJM dispatchers.		2 hrs

		Communications	Description		Time Estimate
Step 2	Emergency Load Management Reductions Action ((30,60, or 120 minute)	PJM-SCC via All-Call SCC – MO	Member Curtailment Service Providers implement load management reductions as requested by PJM dispatchers. Notify governmental agencies SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification	**EEA 2 (DOE Report see note 1)**	2 hrs
	Public Appeal (PJM may issue at other Steps)	PJM –SCC SCC-Corporate Communications	a. Radio and TV alert to general public		1-2 hrs.
		SCC – Customer Services SCC –MO & Regulatory Services	b. Call to Industrial and Commercial Customers, Government Agencies		1-2 hrs.
Step 3	(Real time) Primary Reserve Warning	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC SCC -MO	SCC/MO notify management SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification SCC/MO ensures that all deferrable maintenance or testing affecting capacity or critical transmission is halted. SCC/MO advises all TDC's, Plants, and key personnel as needed MO inform PJM of any environmentally restricted units. MO prepares to load all available primary reserve if requested by PJM SCC contacts MO to determine the status of any requests to alleviate environmental constraints on generating units.		< 1 hr.
Step 4A	(Real time) Maximum Generation Emergency Action	PJM-MO via All-Call PJM-SCC via All-Call MO-PJM SCC-TDC	SCC/MO notify management SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification MO suspend regulation as requested and load all units to Maximum Emergency generation level as required. MO notify PJM of any Maximum Emergency generation loaded prior to PJM request.		< 1hr.

		Communications	Description		Time Estimate
Step 4B	(Real time) Emergency Voluntary Energy Only Demand Response Reduction Action	PJM-SCC via All-Call	Not Applicable SCC/MO notify management SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification		N/A
Step 5	Voltage Reduction Warning & Reduction of Non-Critical Plant Load	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC	AEP doesn't have a Voltage Reduction Program. SCC/MO notifies Transmission/MO management SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification MO to reduce plant load. (See Table III-4)		6-8 hrs. – VR < 1 hr. – plant load
		SCC-Regulatory Services	Notify Government Agencies as applicable		
Step 6	Curtailment of Non-Essential Building Load	PJM-SCC via All Call SCC-Workplace Services	SCC/MO notifies Transmission/MO management SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification Initiate curtailment of AEP building load – 4.4 Mws		< 1 hr
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		PJM –SCC SCC-Corporate Communications	Radio and TV alert to general public		
Step 7	(Real time) Deploy All Resources Action	PJM-MO	MO raise all available online generation to Emergency Maximum At PJM request, MO start offline generation and ramp to full output.	EEA 2	
		PJM-SCC	SCC - notify management of emergency procedure SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification		

		Communications	Description		Time Estimate
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		PJM –SCC SCC-Corporate Communications	Radio and TV alert to general public		
Step 8	(Real-time): Manual Load Dump Warning	PJM-SCC via All-Call SCC– MO-Environmental Services	SCC/MO - notify management of warning SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification Lifting of Environmental Restrictions	EEA 3	
		MO-Environmental Services	Obtain permission to exceed opacity limits Obtain permission to exceed heat input limits Obtain permission to exceed river temperature limits		1-2 hrs.
		MO/Environmental Services	Obtains permission to lift environmental restrictions		
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		SCC-TDC-DDC	Review local computer procedures / dispatch switching personnel to manual load shed		
		SCC-TDC-DDC	Reinforce internal communications to allow load dumping to occur with minimum of delay		
Step 9	(Real-time): Voltage Reduction Action	PJM-SCC via All-Call SCC –TDC & SCC - MO	AEP does not have a voltage reduction program. SCC/MO notifies Transmission/MO management	**(DOE Report)**	< 1 hr.
		PJM –SCC SCC-Corporate Communications	Radio and TV alert to general public		
		SCC-Regulatory Services	Notify Government Agencies as applicable		

		Communications	Description		Time Estimate
Step 10	(Real-time): Manual Load Dump Action	PJM-SCC via All-Call SCC-MO-Environmental Services SCC-TDC-DDC	PJM Allocation based on deficient zones and their share of load to dump Environmental Services/MO lift environmental restrictions on units to regain curtailed generation MW as applicable SCC - notify management of emergency procedure SCC issue Notify PJM_Emer_Procedures email notification SCC issue Notify_TOP_East email notification	**EEA3 (DOE & EEA-3 Report required)**	
		SCC – Corporate Communications Corporate Comm.-CSC SCC – Customer Services SCC – Regulatory Services	Selected distribution customers (manual load curtailment) Notify Government Agencies as applicable	Execute ALS	< 1 hr.
		PJM-MO	Suspend remaining regulation when directed by PJM		
		PJM-SCC-TDC	Dump load equal to or in excess of the amount requested by PJM dispatcher		5 minutes
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		SCC-Corporate Commuications	Public Appeals		
		SCC-TDC	Maintain requested load dump relief until PJM cancels		
		SCC-PJM	Report Mw amount to PJM		

Table III -2 Capacity Deficiency Summary – AEP/PJM

Notes:

1. DOE Report required for Public Appeals / Voltage Reduction called in an EEA 2

Severe Weather Conditions

Cold Weather Alert (PJM)

Excerpts of Severe Weather Conditions (reference PJM Manual M13)

The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide, PJM can initiate a Cold Weather Alert across the RTO or on a Control Zone basis when the forecasted weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below . PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods. PJM will initiate the Cold Weather Alert for the appropriate region(s) in advance of the operating day based on historical experience, information supplied by the pipelines and/or information supplied from the generator owners.

<u>PJM Actions:</u>

- PJM dispatcher notifies PJM management, PJM public information personnel, and members.
- PJM dispatcher issues an Alert and provides the following information:
  - Control Zone
  - Forecasted low temperature
  - Duration of the condition
  - Amount of estimated operating reserve and reserve requirement
  - Reminder to Gen Owners to update their unit parameters in Markets Gateway to reflect revised Start-up and Notification times, max run times, min run times, etc.
  - PJM Dispatch communicates whether fuel limited resources are required to be placed into Maximum Emergency Category.
- PJM Dispatch recalls/cancels non-critical Generation & Transmission maintenance outages.
- PJM Dispatch reviews the load forecast, interchange forecast, the increased MW unavailability from the tables below and generator Times to Start (Start-Up + Notification in Markets Gateway) to confirm if the Day Ahead Market will be able to clear sufficient generation that can be on-line to meet the reliability needs of the system for the operating day. If sufficient generation cannot be cleared in the Day Ahead market based the start-up + notification time, the following processes will be used to commit generation in advance of the Day Ahead Market:

PJM utilizes the following weather locations and approximate unavailability rates to declare a Cold Weather Alerts on a PJM Control Area or Control Zone basis.

Control Zone	Region	Weather	Unavailability
Mid Atlantic	Mid-Atlantic	Philadelphia	4000 - 5000 MW
FE –South/Duq	Western	Pittsburgh	500 – 1000 MW
AEP	Western	Columbus	1000 – 1500 MW
Dayton	Western	Dayton	500 – 1000 MW
ComEd	Western	Chicago	2000 – 3000 MW
Dominion	Southern	Richmond	1000 – 2000 MW
FE West	Western	Cleveland	500 – 1000 MW
DEOK	Western	Cincinnati	200 – 300 MW
EKPC	Western	Winchester	200 – 300 MW

Note: Unavailability numbers are conservative estimates and are not necessarily additive. During the start of extreme cold weather unavailability rates are typically higher. Values can be adjusted based on the duration of cold weather, actual unity performance during cold weather, the impact on fuel sources (i.e., frozen coal, gas interruptions, etc.), the projected level of combined cycle/combustion turbine usage, and level of scheduled long-lead/seldom-run generation.

- When scheduling for a period covered by a Cold Weather Alert, PJM dispatcher may assume an unavailability factor for scheduled interchange that could range from 25% to 75% of the pre-scheduled interchange. PJM Dispatch will make this decision based on the severity of the conditions, recent interchange curtailment experience, and the current/projected impact of the weather system on other Control Areas. This decrease may require the commitment of additional steam units and/or the purchase of emergency power from external systems.
- When in PJM’s judgment combustion turbines in excess of 2000 MW are needed to operate within a control zone, PJM will notify the respective combustion turbine owners that PJM expects these units to be run. If the predicted minimum temperature is -5 degrees Fahrenheit or less or if recent unit performance has shown a significant increase in unit unavailability, an additional level of unavailability is added to the amount of CTs expected to operate. PJM will notify these additional combustion turbine owners that PJM expects these units to be run
- PJM confers with generator owners and if appropriate, directs them to call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up. This includes operations, maintenance, and technical personnel that are necessary to gradually start all equipment during the midnight period. Directions may also be given to bring units on at engine idle, or loaded as necessary to maintain reliability. Once units are started, they remain on-line until PJM dispatcher requests the

units be shut down. Running CTs to provide for Synchronized Reserve is monitored closely for units where fuel and delivery may be hampered. Most troublesome or unreliable units should be started first. PJM dispatch should make this notification on afternoon shift the day prior, paying particular attention to weekend staffing levels.

- PJM dispatch should poll large combined cycle units regarding projected availability during reserve adequacy run.
- PJM dispatch reports significant changes in the estimated operating reserve capacity.
- PJM dispatch cancels the alert if the weather forecast is changed or when the alert period is over.

<u>SCC Actions:</u>

- SCC/MO notifies Transmission/MO management of the alert.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- MO update their unit parameters, including the Start-up and Notification, Min Run Time, Max Run Time, Eco Min, Eco Max, etc. in Markets Gateway
- MO determine whether alternate fuel will be made available to PJM for dispatch. If made available, any known alternate fuel restrictions will be communicated via Markets Gateway in the “operating restrictions” field. If available but only in an emergency, this will also be communicated via Markets Gateway in the “operating restrictions” field.
- MO, based on direction received from PJM call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up. This includes operations, maintenance, and technical personnel that are necessary to gradually start all equipment during the midnight period. The units are brought on at engine idle, where possible, and loaded as necessary to maintain reliability. Once units are started, they remain on-line until PJM dispatcher requests the units be shut down. Running CTs to provide for Synchronized Reserve is monitored closely for units where fuel and delivery may be hampered. Each generator owner attempts to start their most troublesome or unreliable units first.
- MO reviews their combustion turbine capacities, specifically units burning No. 2 fuel oil that do not have sufficient additive to protect them from the predicted low temperature.
- MO/FEL review fuel supply/delivery schedules in anticipation of greater than normal operation of units.
- MO/FEL monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in Markets Gateway.
- MO/FEL contacts PJM dispatcher if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

- MO/FEL contacts PJM dispatch to inform them of gas-fired CTs placed in Maximum Emergency Generation due to daily gas limitations of less than 8 hours (i.e. 5 hours of gas per day)
- SCC/MO/FEL review plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be deferred or cancelled.
- MO will update the "early return time" for any Planned generator outages as indicated in M-10 Section 2.2.2

Hot Weather Alert

The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. PJM may also issue a Hot Weather Alert at lower temperatures during the spring and fall periods if there are significant amounts of generation and transmission outages that reduce available generating capacity.

PJM utilizes the following weather locations and approximate unavailability rates to declare a Hot Weather Alerts on a PJM Control Area or Control Zone basis.

Control Zone	Region	Weather	Unavailability
Mid-Atlantic	Mid-Atlantic	Philadelphia	2000 - 2500 MW
FE South/Duq	Western	Pittsburgh	300 – 500 MW
AEP	Western	Columbus	500 – 1000 MW
Dayton	Western	Dayton	300 – 500 MW
ComEd	Western	Chicago	1000 – 1500 MW
Dominion	Southern	Richmond	500 - 1000 MW
FE West	Western	Cleveland	300 – 500 MW
DEOK	Western	Cincinnati	100 – 200 MW
EKPC	Western	Winchester	100 – 200 MW

PJM Actions:

- PJM dispatch notifies PJM management and member dispatchers.
- PJM dispatch issues an Alert stating the amount of estimated operating reserve capacity and the reserve requirement.
- PJM Dispatch recalls/cancels non-critical Generation & Transmission maintenance outages.
- Reminder to Gen Owners to update their unit parameters in Markets Gateway to reflect revised Start-up and Notification times, max run times, min run times, etc.
- PJM Dispatch communicates whether fuel limited resources are required to be placed into Maximum Emergency Category for Hot Weather/Cold Weather Alerts.

- PJM Dispatch reviews the load forecast, interchange forecast, the increased MW unavailability from the tables below and generator Times to Start (Start-Up + Notification in Markets Gateway) to confirm if the Day Ahead Market will be able to clear sufficient generation that can be on-line to meet the reliability needs of the system for the operating day. If sufficient generation cannot be cleared in the Day Ahead market based the start-up + notification time, the following processes will be used to commit generation in advance of the Day Ahead Market:
- PJM Dispatch will notify the generator owner that the unit is required to be online and ready to follow PJM dispatch signals at XX:XXhrs on XXday for reliability. The unit parameters and the offer will then be confirmed and the unit will be offer capped. PJM dispatch will NOT commit to run the unit longer than its Min Run time.
- PJM dispatch reports significant changes in the estimated operating reserve capacity.

SCC Actions:

- SCC/MO notifies Transmission/MO management of the alert.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- MO update their unit parameters, including the Start-up and Notification, Min Run Time, Max Run Time, Eco Min, Eco Max, etc. in Markets Gateway.
- MO determine whether alternate fuel will be made available to PJM for dispatch. If made available, any known alternate fuel restrictions will be communicated via Markets Gateway in the “operating restrictions” field. If available but only in an emergency, this will also be communicated via Markets Gateway in the “operating restrictions” field.
- MO advises all generating stations and key personnel.
- SCC/MO reviews plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be deferred or cancelled.
- MO/FEL report to PJM dispatcher all fuel / environmental limited facilities as they occur and update PJM dispatcher as appropriate and update the unit Max Run field in Markets Gateway.
- MO/FEL contacts PJM dispatch to inform them of gas-fired CTs placed in Maximum Emergency Generation due to daily gas limitations of less than 8 hours (i.e. 5 hours of gas per day).
- MO will update the “early return time” for any Planned generator outages as indicated in M-10 Section 2.2
- PJM dispatcher cancels the alert, when appropriate.

SPP Weather Emergencies (excerpt of section 9 of SPP BA Emergency Operation Plan)

To maximize the SPP BA's ability to operate reliably during periods of extreme and/or prolonged severe weather conditions, procedures are necessary to keep all affected system personnel aware of the forecast and/or actual status of the system and to ensure that maximum levels of resource availability are attained.

SPP analysis of system conditions during severe weather conditions considers forecasted levels of resource unavailability. SPP uses its best judgment about the magnitude of the projected unavailability of equipment, considering the length of the forecasted and actual weather conditions.

GOPs monitor their fuel supplies and inventories and keep SPP updated about station/units that are experiencing or projected to experience fuel limitations. GOPs are expected to ensure Seasonal Preparedness of their resources. If either the GOP or SPP are concerned about resource availability during weather-related emergencies, conference calls will be initiated to review the operating situations, as appropriate.

Extreme weather events will prompt SPP to notify Stakeholders so they can prepare personnel and facilities for expected extreme conditions. When extreme temperatures are forecasted and expected to persist for an extended period of time, SPP will issue n Weather Alert using Stakeholder notification, and include the following information:

- Impacted area
- Forecasted extreme temperature (highs or lows)
- Forecasted duration of the condition

SPP will also consider appropriate pre-emptive measures, such as:

- Request steps to ensure adequate reserves are available
- Request steps to ensure adequate fuel supplies are available.
- Identify significant changes in the estimated operating reserve capacity for the period

SPP will cancel the extreme weather alert when conditions have moderated**.**

AEP extreme weather actions are listed in the EOP Section VI Transmission Emergency Procedures under Conservative Opereation and Section VII Major Storm Restoration.

AEP West/SPP and AEP East/PJM

Unit	MW (Summer/Winter)
Amos #1	20/40
Amos #2	20/40
Cardinal #1	5/15
Cardinal #2	5/15
Cardinal #3	0/5
Rockport #1	0/5
Rockport #2	5/10
Mitchell #1	10/30
Mitchell #2	20/40
Total System	**85/220**

Table III-3
AEP System - Details of Emergency Capacity Resources Extra Load Capability

Plant	MW	Plant	MW
Amos	2		
Big Sandy	2		
Clinch River	1	Mitchell	1
Cardinal	1	Mountaineer	2
Conesville	6		
D. C. Cook	0		
		Rockport	0
		Total AEP/PJM System	**20**
Flintcreek	1	Northeastern	3
Welsh	1	Pirkey	2
		Total AEP/SPP System	**7**

Table III-4
AEP System - Details of Emergency Capacity Resources Curtailment of Generating Station Use

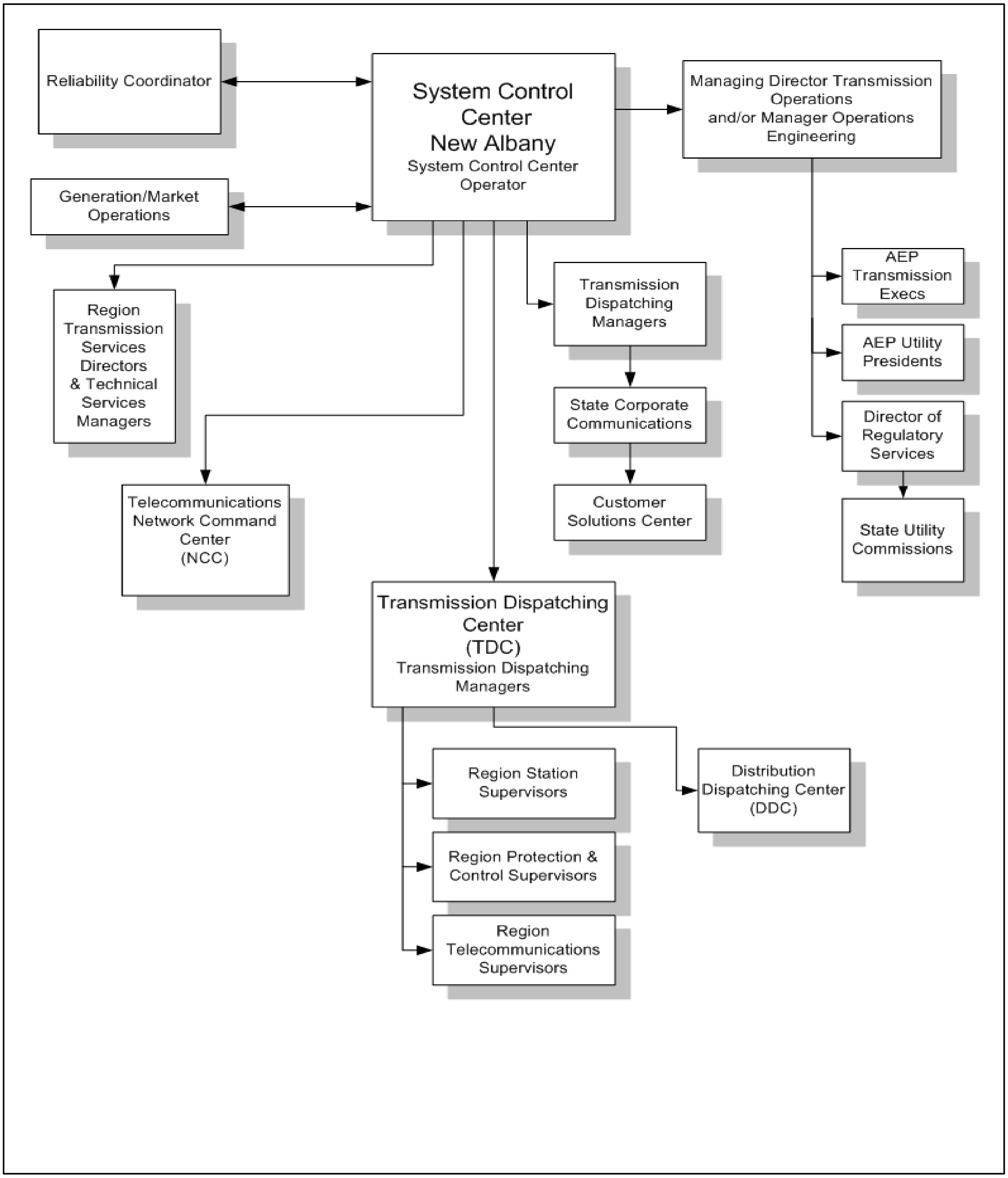


Figure III-1
Capacity Deficiency Warning Notifications

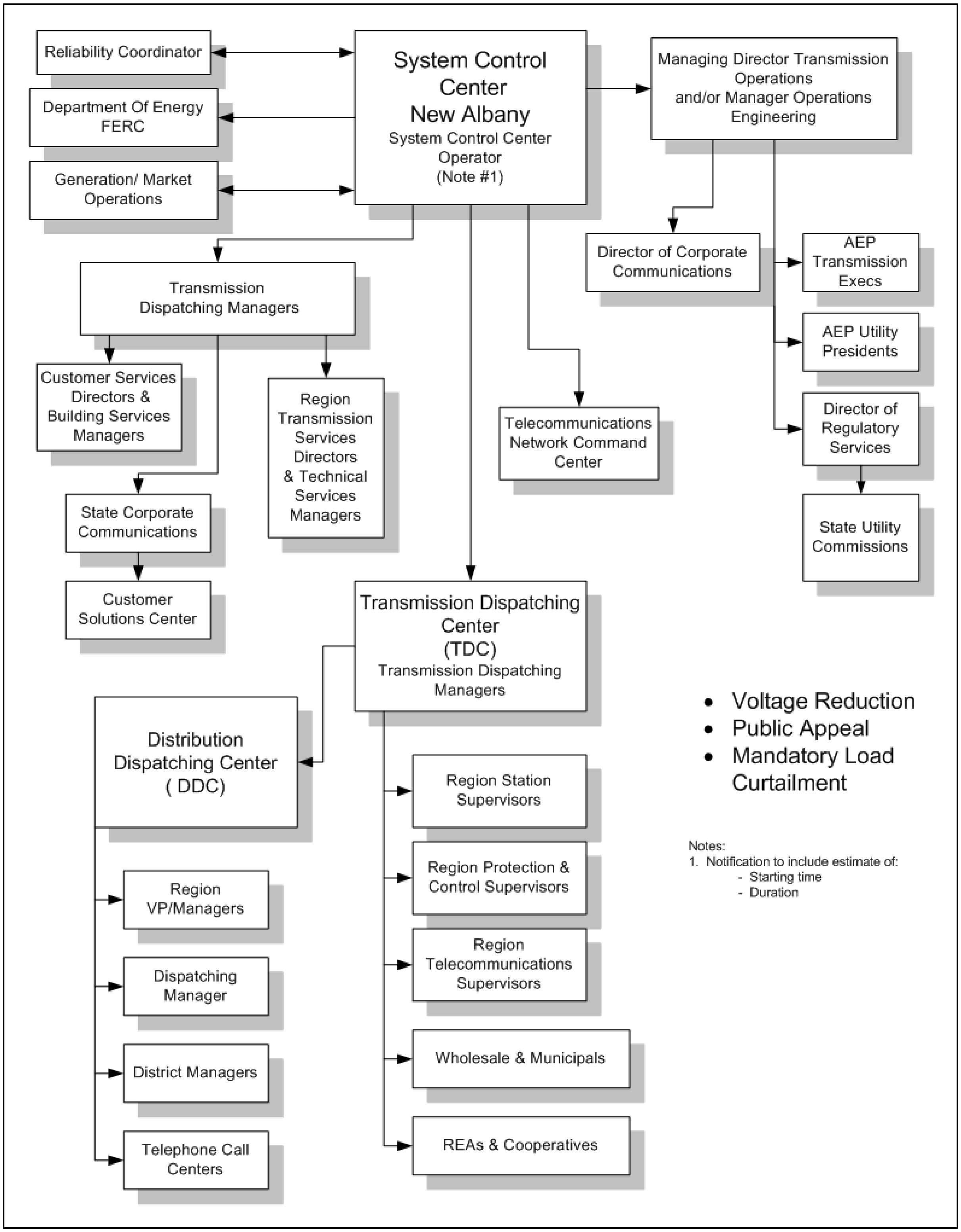


Figure III-2
Capacity Deficiency Action Notifications

Emergency Messages from American Electric Power to the Public

This is an Emergency Message from American Electric Power Company.

Demand for electricity is expected to increase as the (*excessive heat and humidity, excessive cold*) continues. AEP asks customers to conserve electricity, if health permits – especially between (*3 p.m .to 7 p.m. - summer, 6 a.m.-9 a.m. and 3 p.m. to 7 p.m. - winter*)

Electricity customers can take simple electricity conservation steps:

- Close curtains and blinds to keep out the sun (*summer*), and
- Postpone using major electric household appliances such as stoves, dishwashers and clothes dryers until the evening hours, and
- If health permits, set air conditioner thermostats higher than usual (summer), or set heating thermostats lower than usual (winter), and
- Turn off electric appliances and equipment that you do not need or are not using.

Conserving electricity will help ensure adequate power supplies. AEP continues to carefully monitor the power supply conditions. It will do everything possible to keep power flowing in the region.

AEP will keep you informed by radio and television announcements until the problem eases.

AEP thanks you for your cooperation.

Figure III-3
Voluntary Load Curtailment Request to the Public

This is a Further Emergency Message from American Electric Power Company.

The power supply problem announced earlier has become critical.

To avoid widespread blackouts it has become necessary to interrupt electric service to customers for periods ranging from 30 minutes to two hours. To minimize inconvenience, the interruptions will take place on a rotating basis: while some areas will be off, others will be on. Later, the areas of outages will be reversed, so that no group of customers will have to bear all of the inconvenience.

Even while your electric service is on, you can help in this emergency by turning off all appliances, lights, radios, and television sets that are not essential. We recommend that you leave at least one electric light in the "on" position so that you'll know when the power is “on” or “off.”

AEP thanks you for your cooperation in helping us to get through this critical time.

Figure III-4
Mandatory Load Curtailment Initiation Announcement to the Public

This is an Emergency Message from American Electric Power Company.

The power curtailment to AEP's customers is continuing. In an effort to lessen the impact of this emergency on all of our customers, the company is alternating the power cut-off among groups of customers for periods ranging from 30 minutes to two hours. Make sure that all appliances are turned off so that, when the power is restored, it will not cause an overload and create further problems. If you are receiving power, please keep your usage to a bare minimum. Full service will be restored just as soon as conditions permit.

AEP regrets that the critical problem it now faces has made these drastic steps necessary, and thanks all of its customers for their cooperation and understanding.

Further announcements will follow as the situation continues to develop.

Figure III-5
Mandatory Load Curtailment Information Statement to the Public

This is a Message from American Electric Power Company.

AEP reports that the critical electric power shortage has now eased, and full-time electric service has been restored to its customers.

If your electric service is still interrupted, please call the appropriate AEP Customer Solutions Center.

AEP thanks you for your cooperation and understanding. We realize the importance of your electric service.

Figure III-6
Capacity Deficiency Termination Statement to the Public

Section IV

Procedures During Abnormal System Frequency

(DOE Report Required if Load is Shed)

Under-frequency Program

Introduction

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. In the event that a report needs to be filed with the Department of Energy (DOE), NERC, or a Reliability Coordinator, the Security Control Center will prepare those reports and the Transmission Operations Engineering group will review it.

Procedures AEP/PJM

1. From 59.8 - 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.
2. At 59.75 Hz
    a. Suspend Automatic Generation Control (AGC)
    b. Notify Interruptible Customers to drop load
3. At 59.5 Hz automatically shed 5 % System internal load by relay action. (25 cycle, .42 sec. delay)
4. At 59.3 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
5. At 59.1 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
6. At 58.9 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
7. At 58.7 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
8. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.
9. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Automatic Load Shedding Program Specifications

A. Load shedding relays should be accurate to +/- .01 Hz with contact provisions for tripping and automatic restoration. They can be static relays or digital devices and the automatic restoration can be by timer or supervisory control.

B. General guidelines for relay installation are:
   1. A feeder load of 3 MWs or a total station load of 6 MW should be controlled by each static relay or digital device.
   2. Total load to be controlled by load shedding relays should equal 25 % of System internal load.
   3. Under-frequency relays should only be installed on generators or tie lines where necessary; such as, at the D.C. Cook Nuclear Plant.

C. The System is to be designed to provide for manually directed or automatic restoration as follows:
   1. Frequency is to be manually directed to return to 60 Hz by the SCC in conjunction with the MO and interconnections.
   2. Load should be restored only when spinning reserve equals three times the restoration block and due consideration is given to possible automatic reclosing of interconnections by check synchronizing schemes.
   3. Restoration blocks will be determined by:
      a. Automatic Restoration - time delay elements in series with relay reclose contact settings
         i. Both the straight time and integrating timers must complete their sequences before a load block will be restored.
      b. Supervisory Control
         i. UF trip only, no automatic restoration
   4. Each restoration block should represent one percent of system internal load. If a station does not have supervisory control but is located in a metropolitan area, the automatic restoration feature can be disabled and the feeder can be set for a UF trip only.
   5. The restoration frequency should be 59.95 Hz. The time delay settings are shown in the table below:

Load Restored	Integrated Time at or above 59.95 Hz	Straight Time at 59.95 Hz
1st Block - 1%	4 minutes	1 seconds
2nd Block - 1%	4 minutes	2 seconds
3rd Block - 1%	4 minutes	3 seconds
4th Block - 1%	6 minutes	4 seconds
5th Block - 1%	6 minutes	5 seconds
6th Block - 1%	6 minutes	6 seconds
7th Block - 1%	8 minutes	7 seconds
8th Block - 1%	8 minutes	8 seconds
9th Block - 1%	8 minutes	9 seconds
10th Block - 1%	8 minutes	10 seconds
11th Block - 1%	10 minutes	11 seconds
12th Block - 1%	10 minutes	12 seconds
13th Block - 1%	10 minutes	13 seconds
14th Block - 1%	10 minutes	14 seconds
15th Block - 1%	10 minutes	15 seconds
16th Block - 1%	12 minutes	16 seconds
17th Block - 1%	12 minutes	17 seconds
18th Block - 1%	12 minutes	18 seconds
19th Block - 1%	12 minutes	19 seconds
20th Block - 1%	12 minutes	20 seconds
21st Block - 1%	14 minutes	21 seconds
22nd Block - 1%	14 minutes	22 seconds
23rd Block - 1%	14 minutes	23 seconds
24th Block - 1%	14 minutes	24 seconds
25th Block - 1%	14 minutes	25 seconds

Table IV-1
Restoration Blocks - Time Delay Settings

Note: An additional 30 second integrated timer setting is normally applied to the older style mechanical relays.

D. Management of the data and information system relative to the continuing status of the load shedding program is the responsibility of Transmission Operations.

If at any time in the above procedure the decline in area frequency is arrested below 59.5 Hz, an evaluation will be made as to whether the area should manually shed an additional 5 % of its initial load. If, after five minutes, this action has not returned the area frequency to 59.5 Hz or above, the area shall manually shed an additional 5 % of its remaining load and continue to repeat in five-minute intervals until 59.5 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units that are discussed in the subsection: Isolation of Coal-fired Generating Units.

If the recommended limits are exceeded, the subcritical units capable of load rejection should be disconnected by the operation of each unit's generator circuit breaker control switches. The operation should then be continued on a self-supporting basis with the unit carrying its own auxiliaries until such time as it can be reloaded or circumstances suggest that the unit be shut down. The generator voltage regulator must be in service before attempting load rejection; otherwise turbine trip and not load rejection should be applied.

Units not capable of load rejection (supercritical units) should be tripped by operation of the turbine trip switch, which would both avoid the possibility of overspeed as well as result in a transfer of auxiliaries (even at depressed frequencies) which will allow a more orderly shutdown of that unit.

It is important that units not be tripped prematurely when the frequency is declining, as such action will cause the system frequency to decline further.

During any System disturbance involving a declining frequency, the power plant operator should establish communication with the Market Operations (MO). The intent of this recommendation is to assure coordinated restoration procedures. If this attempt with the MO is not successful, communication with the assigned TDC (Transmission Dispatch Center) should be established or, if this fails, with the SCC.

Nothing in the above noted points is intended to alter normal safe operating procedures and good operating judgment.

Procedures AEP/SPP

1. From 59.8 - 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.
2. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load
3. At 59.3 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
4. At 59.0 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
5. At 58.7 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
6. At 58.5 Hz isolate into islands in both PSO and SWEPCO (15 cycle, .25 sec. delay)
   c. PSO - 3 Islands, Refer to PSO UF plan for island boundaries
   d. SWEPCO – 3 Islands, Refer to SWEPCO UF plan for island boundaries.
7. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Step 6 has been developed to isolate systems into islands by opening predetermined interconnect tie lines. The intention of this step is to stabilize generating units, prevent there cascading shut down, and speed restoration of service after frequency has returned to normal. Each of these islands contains multiple generating units belonging to AEP and/or adjacent companies and loads of one or both companies to ensure an island with natural boundaries and a high probability of successful islanding. The probability of successfully maintaining generation stability greatly depends upon the proper matching of the load within each particular island to the attached generator outputs. With the fluctuation of system load varying from maximum summer peak value to 30% of this value at minimum load, the challenge of maintaining unit stability under these load conditions is complicated. Therefore, the following maximum and minimum criteria should be applied to each island:

- The load, at its maximum peak, within an island shall not exceed the total maximum output ratings of the generating units likely to be operating during that time within that island.
- The load, at its minimum level, within an island shall not be less than the minimum output of the smallest unit likely to be operating during that time within that island.

Additionally, the following objectives should be targeted for each island:

- Minimize the percent of time the total load within an island exceeds the maximum total of the ratings of all generating units except the largest within that island.
- Minimize the percent of time the total load within an island is less than the minimum rating of the next to smallest generating unit within that island.
- When both targets above cannot be met, the plan should favor the maximum load conditions in recognition that an underfrequency condition is more likely to occur and the consequences are more serious at maximum load conditions.

Load flow simulations are used to determine that after each step of the plan has operated, the electric system remaining in service will perform successfully within normal and emergency criteria until normal service can be restored to all loads.

Isolation of Coal-Fired Steam Turbine Generation Units

The basic approach to handling sustained frequency deviations on the System is:

1. Utilize emergency capacity resources. (Refer to Section III.)
2. Maintain generating units in service, while attempting to restore the balance between generation and load, until the system frequency excursion exceeds the allowable limits for safe turbine operation as listed in the following subsection: Turbine Off-Frequency Operation.
3. Load-reject subcritical units and trip supercritical units if the system frequency exceeds the allowable limits for the turbine, and be prepared for restoration procedures.

   Since any significant frequency deviation would be accompanied by system separation, it is not possible for any one-control center to direct unit isolation. It is the responsibility of each unit operator to prevent or minimize potential damage to the unit by disconnecting the unit from the System should the frequency excursions exceed the recommended limits noted in the following subsections.

.

Constant Frequency Operations Guide For Fossil Generating Units

Purpose

The purpose of this guide is to describe the AEP System strategy for fossil generating unit operation during a system frequency disturbance.

In most cases, the Market Operations (MO) would direct the response of the generating units to a system frequency disturbance by contacting unit control room operators and requesting the appropriate action**. As long as communications exists with the MO and/or the SCC or TDC, the unit operators should not take individual action.** This guide, however, assumes that a frequency disturbance is experienced in combination with a total loss of communications between the power plants and the MO, and the SCC and TDC. Under these conditions, a predetermined operating strategy is required which coordinates generating unit responses, without integrated instructions from the MO, in order to allow the bulk power system to continue operating in a stable mode.

This guide describes a strategy for fossil generating units to provide a staged, gradual response to frequency deviations without the power plant operators receiving any instructions from MO. This strategy is designed to keep system frequency within reasonable limits while minimizing oscillations that could be caused by individual generating units attempting to operate in a constant frequency mode without centralized guidance.

This guide is not intended to prevent generating unit operators from taking whatever actions are necessary to protect their equipment from potential damage due to off-frequency operation. Limits for allowable off-frequency operation of fossil generating units should be strictly followed to prevent equipment damage. Short term instabilities and power grid outages can only be made worse if permanent damage is allowed to occur to system equipment. The procedures in this guide apply to fossil generating units only. Where possible, hydro units should maintain load during a system frequency disturbance.

Assumptions

The basic assumptions made in the development of this guide are:

Loss of Communications **–** all primary and backup data and voice communication channels are lost between the generating units and the MO, and the SCC and TDC..

Generating Unit Status – sufficient generating capacity remains in service to serve the load over the period of lost communications.

Transmission System Status **–** transmission system congestion does not impose significant constraints on generation unit maneuvering or on providing load service.

Instrumentation **–** generating units are equipped with frequency metering devices capable of displaying the local system frequency on a wide range (roughly 58.0 Hz to 62.0 Hz).

Constant Frequency Operations

General

If communications are lost between a generating unit and the MO and the SCC and TDC, the only information available to the generating unit operator will be frequency as measured locally by plant instrumentation. Under these conditions, the generating unit operator may not be able to determine if the entire grid is still intact or if he is operating as part of a local island. Therefore, any constant frequency operating strategy must function equally well with either an intact grid or with conditions where the grid has broken into islands of generation and load.

In order to restore system frequency and maintain stable system operations, it may be necessary to maneuver generation to match load. During a System disturbance which results in a frequency deviation, the generating units will automatically provide an immediate and sustained response to increase or decrease unit output based upon the settings of the turbine governor and unit controls. Depending upon the cause and magnitude of the frequency deviation, the initial automatic response of the units may not be sufficient to restore System frequency to 60 Hz. By design, turbine governors provide a proportional action only and therefore may steady out at some frequency other than 60 Hz if the load to generation match is not restored. If frequency is not restored by the initial governor action, additional changes in unit generation may be required and should be initiated by the unit operator in accordance with the procedures listed below.

Procedures

Use these procedures only when AGC and all voice communications with the MO and the SCC and TDC have been lost. All means of backup communications should be utilized to reach the MO, SCC and TDC before proceeding with the following actions. As long as communications exists with the MO, the SCC or TDC, the unit operators should not take individual action.

1. As long as frequency remains within a dead band around 60.00 Hz, no control actions should be taken by the generating unit operator to change unit generation beyond sustaining the initial response of the turbine governor and unit controls. For the AEP System, this frequency dead band will be from 59.80 Hz to 60.20 Hz, as shown on Chart 1. When frequency is within this dead band, the unit operator should allow the governor to control unit output and should make no additional corrections to the unit that will affect generation.

2. As frequency moves outside the dead band, the unit operator should manually load or unload the unit in gradual increments in order to avoid overcorrecting and possibly initiating a frequency oscillation. The approximate total generation change required can be given by the formula:

   Mws = 10 ß (F_A – F_S) where ß = - 218 AEP/PJM,

   and ß = - 94 AEP/SPP

   ß = Frequency Bias, $\mathbf{F_A}$ = Frequency Actual, and $\mathbf{F_S}$ = Frequency Scheduled

   As an example, if the AEP/PJM System frequency declines to 59.7 Hz, and the frequency needs to be increased to 59.85 Hz (within dead band)

   Mws = 10 * (-218)(59.7-59.85) = -2180 * -.15 = 327
   Therefore, the AEP/PJM generation would need to increase 327 Mws to cause a .15 Hz increase in frequency.

   While making the appropriate load change, the unit operator should carefully observe frequency and should cease maneuvering the unit when frequency enters the dead band. Stopping within the dead band for some period of time will prevent overshooting or hunting for 60 Hz since the response time of various units to change output will be different and thus, not all units may simultaneously be affecting frequency. Operators should understand that it is not necessary to reach exactly 60.00 Hz but only to attempt to remain in the dead band.

3. After providing the initial manual response, the unit operator should maintain a steady unit output and should continue to closely monitor System frequency. If frequency remains outside the dead band, unit generation should continue to be adjusted in accordance with Table 1 approximately every 5 minutes until frequency enters the dead band.

4. Following the above steps, if frequency still remains outside of the dead band, the generating unit should continue to be maneuvered until reaching its appropriate limit, either fully loaded in the case of a low frequency deviation or at minimum load in the case of a high frequency deviation.

5. If frequency conditions continue to deteriorate, it may be necessary for the unit operator to separate from the grid in order to protect generating unit equipment. Limits for allowable off-frequency operation of fossil generating units should be strictly followed to prevent equipment damage.

   While it is desirable to maintain service continuity, it is imprudent to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that the unit not be prematurely tripped when the frequency is declining, as such action will cause the system frequency to decline further. If the system frequency excursion exceeds allowable off-frequency limits, corrective action should be taken as follows.

   - For subcritical units that are capable of load rejection, load reject and secure the unit in an islanded mode until communications are restored and further instructions are received from the SCC and/or MO. Turbine speed should be adjusted back to near 3600 rpm (60 Hz) after separating from the grid.

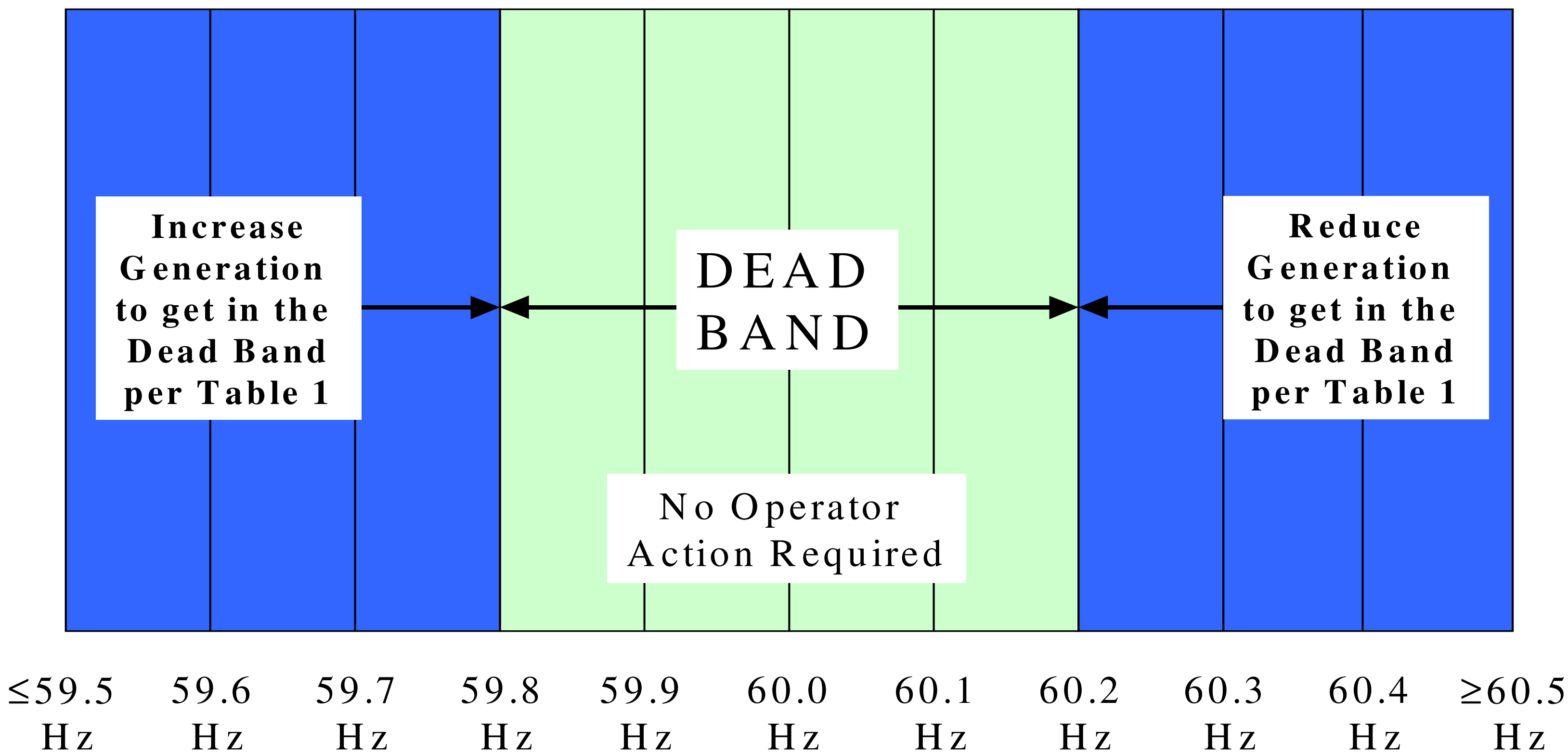
   - For subcritical units incapable of load rejection and for all supercritical units, trip and secure the unit on turning gear until system restoration procedures can be implemented.

6. Units which have been successfully load rejected should not be resynchronized to the grid to address frequency deviation except as directed by the SCC after communications have been restored. It is a higher priority that these units are maintained in an islanded condition in order to support system restoration (Black Start) procedures.

	Turbine Speed (RPM)	
Freq. (Hz)	2-poles	4-poles
59.5	3570	1785
59.6	3576	1788
59.7	3582	1791
59.8	3588	1794
59.9	3594	1797
60.0	3600	1800
60.1	3606	1803
60.2	3612	1806
60.3	3618	1809
60.4	3624	1812
60.5	3630	1815

Chart 1
AEP System
Constant Frequency Operations Guide

1. Use this guide only when all communications have been lost with the SCC
2. Refer to Section IV of the AEP Emergency Operating Plan for allowable off-frequency operating limits



Turbine Off-Frequency Operation

Introduction

The primary consideration for operating a steam turbine generator under loaded condition at other than rated frequency (60 Hz) is protection of the tuned rotating blading at the exhaust end of the low-pressure turbine. In most fossil applications, this may include the last two to three stages (L-0, L-1, and L-2 stages) of blading. Operation with these stages under load at a speed that results in the coincidence of a blading natural frequency and a multiple of actual turbine running speed frequency will lead to blading fatigue damage. Fatigue damage is cumulative over blading service life and will ultimately lead to failure and unit forced outages.

In order to prevent blading fatigue damage, turbine operation at other than rated frequency (hereafter referred to as off-frequency) should be limited. Typically, turbine blading will have an off-frequency range that allows for continuous operation without the potential for blading fatigue damage. Additionally, another off-frequency range or ranges is defined where total accumulated time is limited such that blading fatigue damage is not sufficient to initiate a failure.

The purpose of this subsection is to provide plant operators with recommendations that establish allowable deviation from rated frequency for steam turbine generators under loaded conditions. It is the responsibility of each fossil unit operator to monitor and respond to system frequency excursions in order to prevent blading fatigue damage. .

Recommendations for turbine off-frequency operation contained in this subsection are provided for each of the AEP system units, listed under their respective original equipment manufacturer. Operating parameters defined in the text on the following pages take into account that frequency limitations are applicable to the turbine generator equipment during load operation only and as such do not apply to no-load operation during startup. However, these instructions do apply to units that are operating in a load rejected or islanded mode, and action should be taken to restore and maintain turbine speed at 3600 rpm for these units after separating from the grid.

AEP/PJM - Turbine Generator Units

The following pages provide listings of AEP/PJM Region units and recommendations for each group of units, based on their original equipment manufacturer. The original equipment manufacturers are:

- ABB
- General Electric
- Westinghouse

ABB Turbine Generator Units

These units use the ABB Turbine Generators:

- Cardinal 3
- Amos 3
- Mountaineer 1
- Rockport 1 and 2

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3420 rpm - 3816 rpm	57 Hz - 63.6 Hz	Unlimited (continuous) operation permitted.
Below 3420 rpm	Below 57 Hz	Operation in this speed (frequency) range not to exceed 10 seconds per occurrence.

Table IV-3
Recommendations for ABB Turbine Generators

General Electric Turbine Generator Units

These units use the General Electric Turbine Generators:

- 600 MW Series
  - Cardinal 1 and 2
  -
- 800 MW Series
  - Amos 1 and 2
  - Mitchell 2

Westinghouse Turbine Generator Units

There are two separate sets of recommended turbine off-frequency operating parameters applicable to the Westinghouse turbine-generator sets on the AEP system. These recommended operating limitations are a function of LP turbine last stage blade length and design. This subsection separates recommendations for applicable units according to last stage blade design.

These units use the Westinghouse Turbine Generators with 18, 20, 23, 25 and 26 Inch LP Ends and 32 Inch Ruggedized LP Ends:

- Big Sandy 1
- Conesville 4, 5 and 6

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3510 rpm – 3690 rpm	58.5 Hz - 61.5 Hz	Continuous operation in this speed (frequency) range permitted.
3360 rpm – 3510 rpm	56 Hz – 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the LP blading.

Table IV-5
Recommendations for Westinghouse Turbine Generators
18, 20, 23, 25 and 26 Inch LP Ends and 32 Inch Ruggedized LP Ends

These units use the Westinghouse Turbine Generators with 28.5 through 44 Inch LP Ends:

- Mitchell 1

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3570 rpm - 3630 rpm	59.5 Hz - 60.5 Hz	Continuous operation in this speed (frequency) range permitted.
3510 rpm - 3570 rpm	58.5 Hz - 59.5 Hz	Operation in this speed (frequency) range not to exceed 60 minutes cumulative time over life of the unit.
3360 rpm - 3510 rpm	56 Hz - 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over life of the unit.

Table IV-6
Recommendations for Westinghouse Turbine Generators
28.5 Through 44 Inch LP Ends

AEP/SPP - SWEPCO Region Turbine Generator Units

The following pages provide listings of AEP/SPP SWEPCO Region units and recommendations for each group of units, based on their original equipment manufacturer. The original equipment manufacturers are:

- General Electric
- Westinghouse

General Electric Turbine Generator Units

These units use the General Electric Turbine Generators:

- Arsenal Hill 5
- Flint Creek 1
- Knox Lee 4
- Knox Lee 5
- Lieberman 1
- Lieberman 2
- Lone Star 1
- Wilkes 1
- Wilkes 2
- Wilkes 3

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3564 rpm - 3636 rpm	59.4 Hz – 60.6 Hz	Unlimited (continuous) operation permitted.
3528 rpm - 3564 rpm 3636 rpm - 3672 rpm	58.8 Hz – 59.4 Hz 60.6 Hz - 61.2 Hz	Operation in this speed (frequency) range to be less than 90 minutes cumulative time over the life of the LP blading.
3492 rpm - 3528 rpm 3672 rpm - 3708 rpm	58.2 Hz – 58.8 Hz 61.2 Hz – 61.8 Hz	Operation in this speed (frequency) range to be less than 10 minutes cumulative time over the life of the LP blading.
3456 rpm - 3492 rpm 3708 rpm - 3744 rpm	57.6 Hz – 58.2 Hz 61.8 Hz - 62.4 Hz	Operation in this speed (frequency) range to be less than 1 minute cumulative time over the life of the LP blading.

Table IV-7
Recommendations for SWEPCO Region General Electric Turbine Generators

Westinghouse Turbine Generator Units

There are two separate sets of recommended turbine off-frequency operating parameters applicable to the Westinghouse turbine-generator sets in SPP Region 5. These recommended operating limitations are a function of LP turbine last stage blade length and design. This subsection separates recommendations for applicable units according to last stage blade design.

These units use the Westinghouse Turbine Generators with 20, 23, or 25 Inch LP Ends.

- Knox Lee 2
- Knox Lee 3
- Lieberman 3
- Lieberman 4
- Welsh 1
- Welsh 3

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3510 rpm – 3690 rpm	58.5 Hz - 61.5 Hz	Continuous operation in this speed (frequency) range permitted.
3360 rpm – 3510 rpm	56.0 Hz – 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the LP blading.
<3360 rpm - >3690 rpm	<56.0 Hz or > 61.5 Hz	Trip Unit Immediately

Table IV-8
Recommendations for SWEPCO Region Westinghouse Turbine Generators
20, 23, or 25 Inch LP Ends

These units use the Westinghouse Turbine Generators with 28.5 Inch LP Ends:

- Pirkey 1
- Dolet Hills 1

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3570 rpm - 3630 rpm	59.5 Hz - 60.5 Hz	Continuous operation in this speed (frequency) range permitted.
3510 rpm - 3570 rpm	58.5 Hz - 59.5 Hz	Operation in this speed (frequency) range not to exceed 60 minutes cumulative time over life of the unit.
3360 rpm - 3510 rpm	56.0 Hz - 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over life of the unit.
<3360 rpm - >3690 rpm	<56.0 Hz or > 61.5 Hz	Trip Unit Immediately

Table IV-9
Recommendations for SWEPCO Region Westinghouse Turbine Generators
28.54 Inch LP Ends

AEP/SPP - PSO Region Turbine Generator Units

The following pages provide listings of AEP/SPP PSO Region units and recommendations for each group of units, based on their original equipment manufacturer. The original equipment manufacturers are:

- ABB
- General Electric
- Westinghouse

<u>General Electric Turbine Generator Units</u>

These units use the General Electric Turbine Generators.

- Northeastern 2
- Northeastern 3
- Riverside 2

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3564 RPM - 3636 RPM	59.4 Hz - 60.6 Hz	Continuous Operation
3636 RPM - 3672 RPM 3564 RPM - 3528 RPM	60.6 Hz - 61.2 HZ 59.4 Hz - 58.8 Hz	Operation in this speed (frequency) range not to exceed 100 minutes cumulative time over the life of the machine
3672 RPM - 3708 RPM 3528 RPM - 3492 RPM	61.2 Hz - 61.8 Hz 58.8 Hz - 58.2 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
3708 RPM - 3744 RPM 3492 RPM - 3456 RPM	61.8 Hz - 62.4 Hz 58.2 Hz - 57.6 Hz	Operation in this speed (frequency) range not to exceed 1 minutes cumulative time over the life of the machine
More than 3744 RPM Less than 3456 RPM	More than 62.4 Hz Less than 57.6 Hz	Trip Unit Immediately

Table IV-10
Recommendations for PSO General Electric Turbine Generators

Westinghouse and ABB Turbine Generator Units

These units use the Westinghouse Electric Steam Turbine Generators.

- Northeastern 1
- Southwestern 1
- Southwestern 2
- Tulsa 2
- Tulsa 3
- Tulsa 4

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3510 rpm - 3690 rpm	58.5 Hz - 61.5 Hz	Continuous Operation
3690 rpm - 3780 rpm 3510 rpm - 3420 rpm	61.5 Hz - 63.0 HZ 58.5 Hz - 57.0 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
More than 3780 rpm Less than 3420 rpm	More than 63.0 Hz Less than 57.0 Hz	Trip Unit Immediately

Table IV – 11
Recommendations for PSO Westinghouse Steam Turbine Generators

These units use the Westinghouse Electric Turbine Generators.

- Comanche Steam Turbine (ST-1)
- Riverside 1
- Southwestern 3

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3570 rpm - 3630 rpm	59.5 Hz - 60.5 Hz	Continuous Operation
3630 rpm - 3690 rpm 3570 rpm - 3510 rpm	60.5 Hz - 61.5 HZ 59.5 Hz - 58.5 Hz	Operation in this speed (frequency) range not to exceed 60 minutes cumulative time over the life of the machine
3690 rpm - 3780 rpm 3510 rpm - 3420 rpm	58.5 Hz - 57.0 Hz 58.5 Hz - 57.0 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
More than 3780 rpm Less than 3420 rpm	More than 63.0 Hz Less than 57.0 Hz	Trip Unit Immediately

Table IV – 12
Recommendations for PSO Westinghouse Turbine Generators

These units use the Westinghouse Electric and ABB Gas Turbine Generators.

- Comanche GT 1
- Comanche GT 2
- Weleetka GT 4
- Weleetka GT 5
- Weleetka GT 6

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3480 rpm - 3720 rpm	58.0 Hz - 62.0 Hz	Continuous Operation
3720 rpm - 3840 rpm 3480 rpm - 3360 rpm	62.0 Hz - 64.0 HZ 58.0 Hz - 56.0 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
More than 3840 rpm Less than 3360 rpm	More than 64.0 Hz Less than 57.0 Hz	Trip Unit Immediately

Table IV – 13
Recommendations for PSO Westinghouse and ABB Gas Turbines

Section V

Fuel Limitations

Introduction

NERC EOP-001-2.1b required an emergency plan for fuel supply and inventory. EOP-001-2.1b was retired on March 31,2017 per FERC Order 818. EOP 011-1 effective April 1, 2017 requires the Balancing Authority to have an emergency plan for fuel supply and inventory.

AEP is not registered as a Balancing Authority.

Fuel supply emergencies having an impact on the Bulk Electric System require an OE-417 report to DOE. Refer to section IX of the EOP for details. In the event that a report needs to be filed with the Department of Energy (DOE), NERC, or a Reliability Authority, the Transmission Operations Engineering group can assist in preparing these reports.

Section VI

Transmission Emergency Procedures

References

PJM Transmission Operations Manual M03 rev 52
Emergency Manual M13 rev 65
Generation Operational Requirements M14D rev 42
Reliability Coordination M37 rev 14
SPP Planning Criteria rev 1.3
SPP Operating Criteria rev 1.4
SPP BA Emergency Operating Plan v6
SPP Integrated Marketplace rev 42
SPP IROL Relief Guides dated 04/07/2017
NERC Emergency Operations Standards
EOP 011-1 Emergency Operations
NERC Transmission Operations Standards
TOP-001 Transmission Operations
TOP-002 Operations Planning

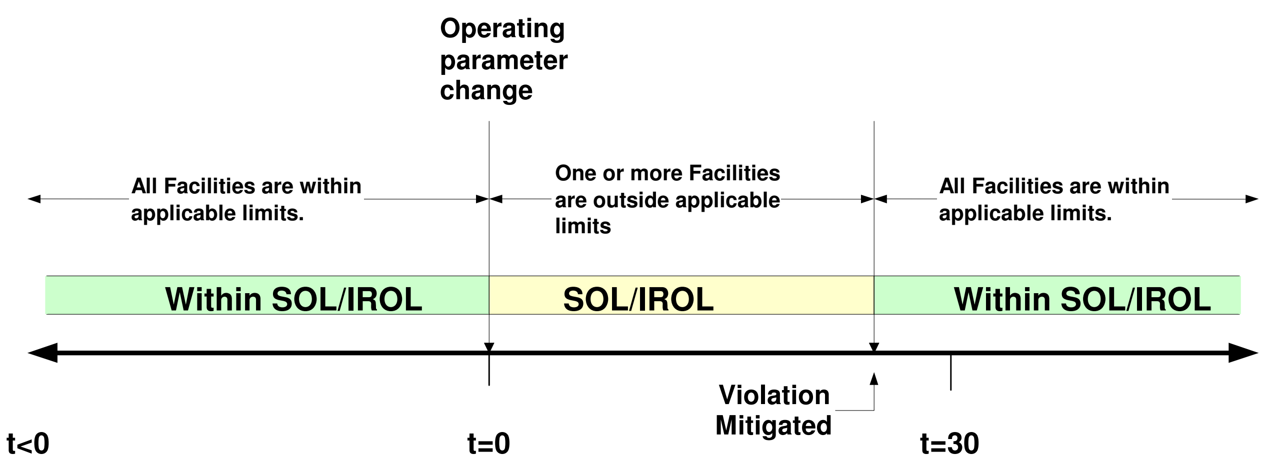
SOL/IROL Definitions

NERC Standard TOP-001 and TOP-002 outlines specific requirements and identifies accountability for developing and implementing Operating Plans to alleviate System Operating Limits (SOL) and Interconnected Reliability Operating Limits (IROL). The definitions of a SOL and IROL are as follows:

System Operating Limit (SOL). The value (such as MW, MVar, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

Interconnected Reliability Operating Limit (IROL). A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.



Introduction and Conditions

The AEP transmission system may be subject to transmission overloads or excessively low voltages during abnormal conditions. Internal loads can exceed forecasts during very hot or very cold conditions when load growth exceeds system design and new facilities are not yet in place. Capacity deficiencies in one part of the eastern interconnected network can stress AEP transmission facilities between the deficient areas and areas of excess generation. Likewise, economic interconnected operation can result in AEP transmission facilities being overloaded between available economic generation and high cost generation areas. The result of any one of these conditions or other reasons, separately or in combination, could cause unacceptable operating conditions for the AEP transmission system. With these variables in mind, AEP must operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. AEP will work in conjunction with the applicable Reliability Coordinator to mitigate any transmission emergencies on the AEP system and, should an emergency occur, will make every effort to remain connected to the Interconnection unless such actions would violate safety, equipment, regulatory or statutory requirements. The AEP Transmission System Control Center (SCC) shall comply with all Operating Instructions issued by the applicable Reliability Coordinator as outlined in Appendix VI – Responsibility and Authority. In instances where there is a difference in derived operating limits, the AEP transmission system shall always be operated to the most limiting parameter. An overview of the mechanisms to mitigate transmission emergencies is outlined below.

Should an event occur that requires filing a report with the Department of Energy (DOE), NERC, or a Reliability Coordinator, Real Time Operations will prepare those reports with assistance from the Transmission Operations Engineering group and/or the applicable Transmission Dispatch Center personnel.

There are four general types of conditions that will require action:

1. **Contingency Thermal Overloads**
   The outage of one facility will load a transmission element to or above its emergency capability. Loadings must be controlled to no more than the emergency ratings in advance of the contingency occurring unless the overload can be controlled within a short time after the contingency. Additional measures may need to be taken upon the loss of a critical facility.

2. **Contingency System Stability Over Limits**
   The system is transmitting power at a level at which a critical outage of one facility will cause a virtually instantaneous separation across the path over which the power is being transmitted, possibly resulting in cascading outages. Path flows must be reduced immediately to safe levels, or maintained below the stability limits.

3. **Contingency Voltage Under/Over Limits**
   The voltage level is at a level at which the loss of a critical facility will result in unacceptably low voltages. If the voltage is not increased within a matter of a few seconds to a few minutes after the contingency occurs, cascading facility outages, equipment damage for customers and AEP, and/or loss of customer load will occur. Loading levels must be reduced or other measures must be taken to immediately raise voltages before a critical contingency occurs. Also, during light load conditions, system voltages may become unacceptably high.

4. **Actual Thermal Overloads and/or Actual Voltage Under/Over Limits**
   Transmission thermal loadings are above rated capabilities and/or voltage levels are at, below or above levels that will result in equipment damage and/or cascading outages. Action must be taken immediately to reduce facility loadings and/or raise or lower voltages.

Transmission Reserve Warning (TRW)

If a transmission emergency exists or is anticipated, a Transmission Reserve Warning (TRW) will be issued by the SCC for the area affected. When a TRW is issued, all station or transmission maintenance, testing, or construction work scheduled or in progress in the affected area will be reviewed to determine if such work should be cancelled or deferred to safeguard system transfer capability and reliability. Also, transmission facilities scheduled out of service will be reviewed and be returned to service if it is determined that returning the facility will alleviate the emergency condition. Generation scheduled/opportunity outages and maintenance work will also be reviewed to determine if returning the units will alleviate the emergency condition.

The SCC will notify the Reliability Coordinator of the current and projected conditions for the emergency.

Emergency Actions

This plan reflects these basic principles:

1. All possible actions will be taken before load shedding is implemented.
2. Load shedding will be used under emergency conditions to prevent cascading outages, and the spread of customer outages.
3. The transmission and generation system must be maintained as intact as possible in order to restore the system and customer loads as quickly as possible.
4. Load shedding will be targeted to minimize the amount shed by choosing loads that will effectively help the emergency condition(s).

When action is required because of transmission overloads or low voltages, a variety of measures can be used for relief. The order of application of transmission relief measures will depend upon the specific problem that exists and the time required to implement each measure. The SCC will work with the Reliability Coordinator, and under NERC guidelines, to achieve an effective and timely resolution of each problem. The following key points relate to TLR's and voltage criteria.

- The NERC Transmission Loading Relief (TLR) Procedures can be found in Table VI-2.
- It is important to maintain adequate pre-contingency voltage levels on the transmission system to prevent loss of load due to low voltage conditions, maximize the amount of power that can be transmitted over the power system, and prevent high voltage conditions.
  - AEP East and West Baseline Voltage Limits are provided below.

AEP East Baseline Voltage Limits*			
Limit	765 kV	500 kV	345 kV to 69 kV
High	1.05 pu (803.2 kV)	1.10 pu (550 kV)	1.05 pu

Normal Low	.95 pu (726.8 kV)	1.00 pu (500 kV)	.95 pu
Emergency Low	.92 pu (703.8 kV)	.97 pu (485 kV)	.92 pu
Load Dump	.90 pu (688.5 kV)	.95 pu (475 kV)	.90 pu
Voltage Drop	10%	8%	8%

AEP SPP Baseline Voltage Limits*	
Limit	345 kV to 69 kV
High	1.05 pu
Normal Low	.95 pu
Emergency Low	.90 pu**

*Exceptions to the High voltage baseline limits can be found in the Appendix II.

**SPP Planning Criteria states voltages shall be maintained above 0.90 pu under single contingency conditions. For conservatism and improved situational awareness, AEP Transmission Operations monitors at 0.92 pu under contingency conditions.

- Voltage Control – AEP/PJM
  - Typically try to maintain voltage levels from 96.0 to 102.0 % on the 765 kV transmission systems.
  - Typically try to maintain voltage levels from 101.0 to 105.0 % on the 500kV transmission system.
  - Typically try to maintain voltage levels from 95.0 to 105.0 % on the 345 kV to 69 kV transmission systems.
  - Maintain schedules at Generating Plants
    - Voltage ± 0.5% (unless specified otherwise by TOPS)
    - Power Factor ± 2% (unless specified otherwise by TOPS)
  - Avoid high voltage limits at the EHV and Transmission levels. AEP's 765kV circuits have overvoltage relay settings that will automatically trip the line circuit breakers if triggered on an individual phase. Refer to Appendix II.

- Voltage Control – AEP/SPP
  - Typically try to maintain voltage levels from 95.0 to 105.0 % on the 345 kV,161 kV, 138 kV & 69 kV transmission systems.
    - 345 ± 17 kV, 161 ± 8 kV, 138 ± 7 kV, 69 ± 4 kV
  - Maintain schedules at Generating Plants
    - Voltage ± 0.5% (unless otherwise specified by TOPS)
    - Power Factor ± 2% (unless otherwise specified by TOPS)
  - Avoid high voltage limits on Transmission equipment, particularly on the EHV. There are select 345 kV circuits that have overvoltage relay settings (typically 1.06pu with a

several minute timer delay) that will automatically trip the line circuit breakers if triggered

Minimize the reactive loading on units by balancing reactive loading among units closely connected to the same electrical bus.

All generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode, maintaining network voltage and/or reactive power as required. Therefore, regardless of schedule type, all generators connected to the AEP transmission system shall operate with their automatic voltage regulators in service and controlling voltage and shall not use reactive power or power factor controllers, unless otherwise authorized by TOPS. Wind Farms do not typically utilize traditional AVRs, but rather utilize various reactive management systems to adhere to scheduled voltage/reactive requirements. All wind farms connected to the AEP system shall operate with their reactive management system in service. All units are expected to notify TOPS within 30 minutes of any change in status to the AVR control systems, including power system stabilizers (PSS), if applicable, that would not allow for automatic control of the voltage set point. Refer to the "Generator AVR Status Change and Voltage Monitoring" document and the individual generator voltage/power factor schedule letters (TOPS ShareNow / Engineering / Operating Guidelines / AEP System Wide Guidelines and Information / Voltage Schedule Details) for additional details regarding AVR/PSS or wind farm reactive management system status changes.

Long-term changes in the voltage or power factor schedule will be determined by AEP's Transmission Operations organization and provided to the Generation Owners/Operators. Short-term changes in the voltage or power factor schedule required to address extreme system conditions are also determined by Transmission Operations and provided to the Generation Owners/Operators. Any changes in voltage or power factor schedule shall be coordinated with the appropriate Reliability Coordinator (PJM or SPP).

The Voltage_and_Reactive_Guide_AEPE_AEPW-SPP lists specific actions to be taken by the System Control Center Operator, Reliability Coordinator, and Transmission Dispatchers to control voltage. The document is stored on the AEP TOPS ShareNow at **Engineering>Operating Guidelines>AEP System Wide Guides and Information>Voltage and Reactive Guides.**

The transmission measures that will be used for transmission emergencies will include any or all of the following:

1. Any available shunt or bridge capacitors not already in service in a low voltage area will be placed in service and any 765 kV or 345 kV shunt reactors not already out of service in the low voltage area will be removed from service if they can be removed without switching circuits and causing a high voltage condition.
2. Adjusting set point of static VAR compensators (SVC).
3. Operating synchronous condensers.
4. AEP generators will be requested to maximize MVAR output to improve voltage profiles and alleviate transmission system low voltage conditions. Typically a 1-2 % increase in voltage schedule will be requested.
5. On-line IPP's and Co-generators should be contacted to supply maximum available MVARs to the transmission system in order to improve voltage profiles and reactive reserves in accordance with contracts and/or agreements.

6. Series capacitors and reactors whose insertion or removal from service will divert power from a loaded facility and/or increase voltage in a low voltage area will be used to improve system conditions.
7. Capacity resources that may be useful will be used. These may include:
   a. Curtailment of generating station use
   b. Curtailment of unessential building use
8. Reconfigure the transmission system by removing (or returning to service if possible) facilities that will make a significant improvement to the problem area without causing uncontrollable problems elsewhere.
9. PJM Locational Marginal Pricing (LMP) to control congestion.
10. SPP Locational Imbalance Pricing (LIP) to control congestion.
11. Curtailment of Non-Firm transmission service, beginning with the lowest priority reservation, in accordance with NERC Standard IRO-006. Transactions will be curtailed that have a response factor of at least 5% on the overloaded facility or have a significant impact on the voltage problem. Coordination with adjacent systems will ensure that all transactions that meet these criteria will be cancelled, whether or not AEP is directly involved in a given transaction.
12. Re-dispatch generation by reducing units that have large response factors that load the overloaded facility and increasing units with large response factors to unload the overloaded facility.
13. Contact major industrial/commercial customers to reduce load in specific regional areas that will help alleviate the emergency condition.
14. Voluntary load curtailment in the specific regional areas that will alleviate the emergency condition.
15. Purchase power from IPP's, Co-Gen's, or other Market Entities, regardless of cost, and in a direction that will help alleviate the emergency condition.
16. Curtailment of Firm transmission service in accordance with NERC Standard IRO-006, on a pro-rata basis with native and network loads, that have a response factor of 5% or more on the overloaded facility or a significant positive impact on the low voltage area will be curtailed after preceding steps have been implemented or if the preceding steps are not anticipated to provide adequate relief.
17. If an overload or abnormal voltage or reactive condition persists on a transmission facility and equipment is endangered, the affected facility shall be disconnected. In doing so, AEP shall notify the applicable Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
18. If the above steps prove to be inadequate then all other available emergency procedures will be implemented including load shedding.

Additionally, some customer loads connected to AEP's transmission and sub-transmission network, such as municipalities and various Co-ops, are served in whole or in part by non-AEP generation and have transmission service agreements with AEP. FERC open transmission access regulations require that AEP treat these transmission customers in a manner comparable to the service provided to AEP's own internal customers. In addition, a few large industrial customers cannot be shed at AEP supply points without fractionalizing the transmission or sub-transmission network and reducing reliability. AEP will request that these municipalities, Co-ops, and industrial customers develop plans for shedding of their load when directed by the SCC. Supervisory controlled loads will be capable of shedding load within 15 minutes of a critical contingency unless otherwise noted. While it is recognized that municipalities, Co-ops, and large industrials do not have this capability, they will be requested and expected to shed load within 15 minutes of notification that a critical contingency has occurred. A DOE report is required for voluntary load curtailment and manual load shedding.

Copies of the Transmission Emergency Plans and Memo's for specific transmission emergency procedures are located on the TOPS ShareNow as noted below.

The TOPS AEP Congestion Management Guidelines for the AEP/PJM/SPP areas have specific actions to be taken by the System Control Center Operator and Reliability Coordinator for congestion events. The AEP Congestion Management Guidelines document is located on the AEP TOPS ShareNow at **Engineering>Operating Guidelines>AEP System Wide Guidelines and Information>AEP Congestion Management Guidelines**

The PCLLRW-PCAP Procedure document located on the AEP TOPS ShareNow at **SCC>SCCO All Inclusive>PCLLRW-PCAP Procedure** outlines processes for contingency load relief, including local load shedding.

> The PJM pull down menu under the Switching tab on the AEP URL http://topsweb/PCLLRW/Default.aspx documents the switching / load shed solutions for potential PCLLRW contingencies.
>
> Likewisethe SPP pull down menu under the Switching tab on the AEP URL http://topsweb/PCLLRW/Default.aspx documents the switching / load shed solutions for potential PCAP contingencies.

TOPS_IROL_Relief_Procedures_AEPE_PJM contain specific actions to be taken by the System Control Center Operator and Reliability Coordinator for IROL events. The document is on the AEP TOPS ShareNow at: **Engineering>Operating Guidelines>AEP East>General** for the East area.

Per Section 3.1: SOL and IROL Limit Determination of PJM Manual 37: PJM has developed a SOL Methodology for use in the Operating Horizon to ensure reliable BES performance. Including the dynamically calculated limits for the IROL facilities, the most restrictive applicable limit (thermal / voltage / transient stability / voltage stability) upon all BES facilities and "Reliability and Markets" sub-BES facilities as listed on the PJM Transmission Facilities pages, http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx are considered System Operating Limits (SOL). PJM manual 3 Section 5 lists a potential IROL facility that is managed by PJM / MISO via conservative operations.

PJM manual 03 - Section 1, Note states:

> AEP is the registered TOP for the AEP 138 kV and below facilities. ITCI is the registered TOP for its facilities. PJM is the registered TOP for all other BES facilities on the AEP transmission system. Under normal operating conditions AEP will coordinate with PJM to re-dispatch generation to control flows on their 138 kV and below monitored facilities. In an Emergency, AEP will notify PJM of any unilateral actions it has taken with respect to the re -

dispatch of generation as soon as practicable, but no later than 30 minutes, so that PJM can coordinate with the impacted parties.

The SPP IROL Relief Guide, as posted on the SPP Globalscape Web Transfer Client , lists the IROL facilities in the SPP area. Section 7.3 of SPP Planning Criteria uses flowgate limits as the SPP System Operating Limits. SPP utilizes these flowgates to ensure the system is operating within acceptable reliability criteria.

The AEP Transmission Operations Coordination and Communications of Ratings document outlines a process for communicating AEP facility ratings. AEP Transmission Operations is responsible for maintaining accurate ratings within the SE and communicating rating changes to the applicable RC. AEP Transmission Operations is notified by AEP Transmission Planning of rating changes as the Kremlin databases are updated with revised rating information. Transmission Operations can act as a catalyst to initiate facility rating reviews, as Transmission Operations becomes aware of planned and unplanned outages and system changes that can impact facility ratings. Upon completion of a facility rating review and official notification of the facility rating change; Transmission Operations updates the SE and TDC SCADA systems and provides this information to the RC through established processes. For additional details refer to **the Coordination_Communications of Ratings_R5 document on TOps ShareNow at Engineering>Ratings Coordination**

AEP is the registered Transmission Operator (TOP) for AEP facilities in the AEP West/SPP footprint. SPP is not registered as a TOP.

Remedial Action Scheme (RAS) in AEP/SPP and AEP/PJM Area

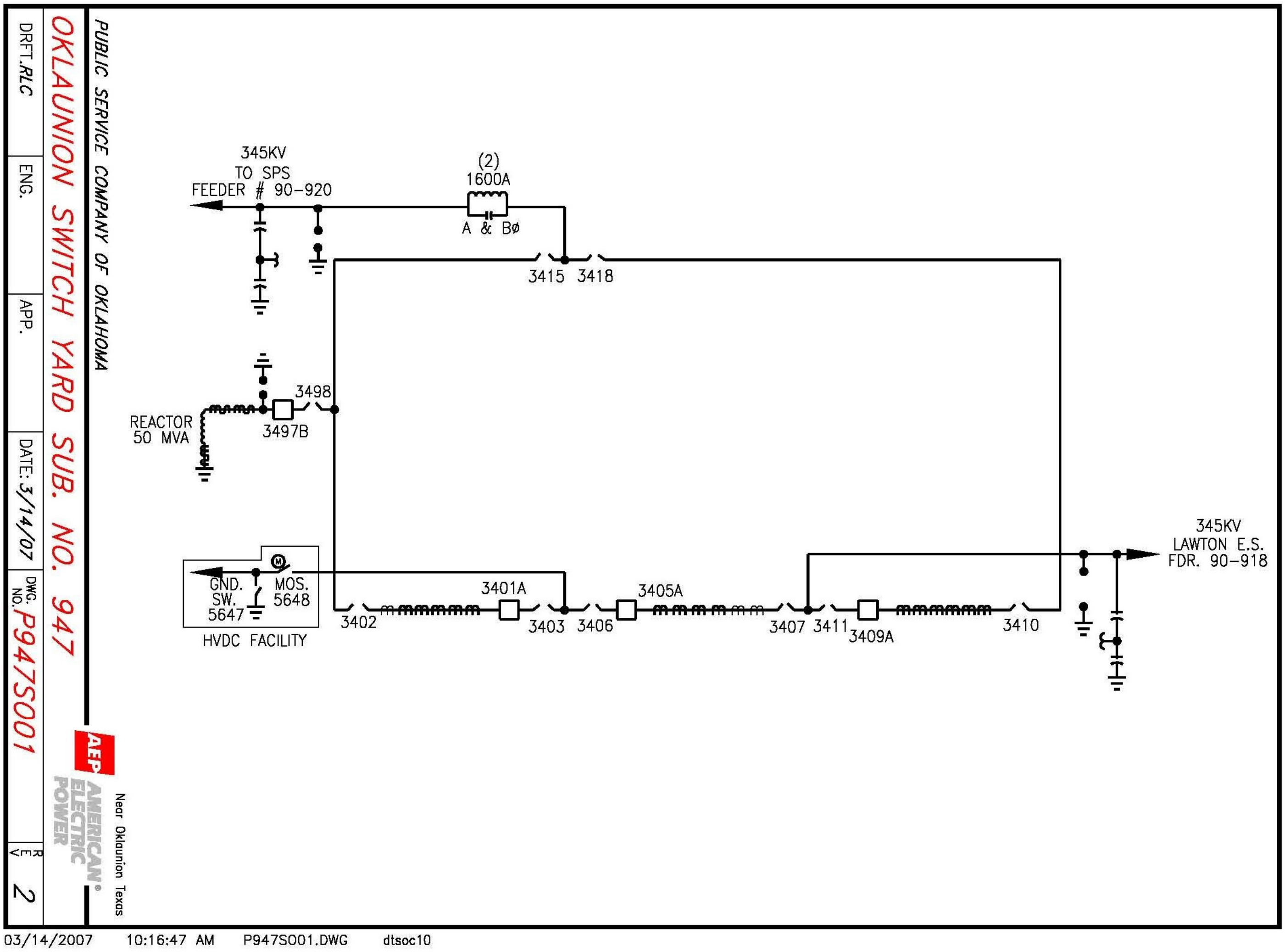
A. AEP/SPP – Oklaunion SUB 90-947 [redacted]

System Description

The AEP/Public Service Co. of Oklahoma (PSO) [redacted] Station [redacted] the electric power systems of the [redacted] and the [redacted] The [redacted] line exiting to the east connects to [redacted] substation. The [redacted] line exiting to the west connects to [redacted] substation [redacted] is a PSO substation. [redacted] is a [redacted] substation. The [redacted] substation was constructed in the mid-1980's.

[redacted] **Special Protection System (SPS) description and summary of functionality:**

At [redacted] substation, any time both breakers [redacted] and [redacted] are tripped [redacted] that is line [redacted] is taken out, [redacted] of breaker auxiliary contacts from these breakers will [redacted] through [redacted], which drops the [redacted] and isolates the [redacted]. This mode of operation is necessary to avoid (1) potential transmission overload problems and possible isolation of the [redacted], (2) potential low voltage problems due to heavy power flows and (3) potential high voltage problems that can result in equipment damage if the [redacted] leaving the [redacted] and [redacted] in-service. Utilizing [redacted] sets of [redacted] indication auxiliary contacts, the [redacted] will be simple, reliable and redundant.



The following process will be implemented to ensure compliance with the NERC requirements:

1. Authorization by the TULSA TDC is required whenever the primary [redacted] is taken out of service.
2. The Tulsa TDC shall notify the AEP West System Control Center Operator whenever the primary [redacted] is taken out of service, and is returned to service..
3. As stated in the Purpose statement, the [redacted] is always in service except as noted in item 2 above.
    a. When the [redacted] have operated, AEP assumes the [redacted] has operated.
    b. Protection and Control investigates and determines if the [redacted].
    c. Protection and Control Asset Engineering notifies SCC of any [redacted].
4. The AEP West System Control Center Operator shall notify the SPP Reliability Coordinator / ERCOT whenever the primary [redacted] has operated, is taken out of service, or is returned to service.

5. The AEP West System Control Center Operator shall notify Xcel Energy (neighboring TOP) whenever the primary [redacted] has operated, is taken out of service, or is returned to service.
6. The AEP West System Control Center Operator shall notify the following groups internal to AEP whenever the primary [redacted] is assumed to have operated as noted in 3a:

   NOTIFY_TOPS_WEST
   NOTIFY_EHV Transmission Outages
   NOTIFY_Management Team
   PSO Transmission Dispatch
   Transmission Reliability Compliance (TRELCOMP)
   Protection & Controls Asset Engineering (PCAE_W)
   Tech Support Tulsa / Shreveport (TRO Tech Support Tulsa Shrev)
   Advanced Transmission Studies & Technologies (ATST)

[redacted]

AEP/PJM – [redacted]

System Description

[redacted] Remedial Action Scheme (RAS)

On August 4, 2007, an unusual series of electrical faults caused the loss of [redacted] and several non-AEP units in the area. NERC investigated this event and developed recommendations documented in the report "[redacted]. In response to recommendations from NERC related to the [redacted], AEP made enhancements to the Fast Valve controls to cover multiple, random faults resulting in multiple fast valve initiates. The enhancements in the Fast Valve scheme introduced the need for a Special Protection System (SPS). The enhancements to the Fast Valving Controls and the addition of the SPS is designed to address the type of unusual series of sequential faults experienced during the [redacted] disturbance and provides coordination between plant and transmission line protection equipment.

As part of an additional investigation, initiated by RFC in 2010, regarding the [redacted] described above, AEP has concluded that the Fast Valving (FV) and Emergency Unit Trip (EUT) special controls shall be included as part of the [redacted] Protection System definition. The existing functionality of these controls has not changed; however, all Transmission and Generation operation, relay and maintenance activities associated with these controls will be modified to conform with the requirements of a Special Protection System as defined by NERC.

Fast Valving (FV) has been removed from this definition as part of the transition from the previous [redacted] to the new [redacted] requirements. The [redacted] is classified as the [redacted] under the new [redacted] requirements.

The [redacted] is defined as:

1. **[redacted] control logic,**
2. **[redacted].**

The following is a description of each component of the Rockport Special Protection System and corresponding Transmission Operator actions should a [redacted] occur:

Unit RAS Trip

The Unit RAS Trip is required due to the impact that a [redacted] has on the units. Both the [redacted] & [redacted] in the turbine increase during each [redacted] operation. There are imbedded safe operating limits that [redacted] for [redacted]. Exceeding either of these safety limits requires the unit to be tripped. Since both Rockport units [redacted] and respond similarly when at the same MVA output levels, there is the potential that both units will trip simultaneously. To prevent the tripping of both units by the imbedded safety operating limits systems the [redacted] was installed.

**** ACTIONS FOR THE SCC RELIABILITY COORDINATOR TO TAKE ****

The SCC Desk will receive a single alarm of "[redacted]" when the [redacted] (Alarm points on the **LRSR** and **PI** displays will also change status accordingly). The SCC shall log the alarm in DOL and notify the following groups:

Columbus West TDC
PJM
Production Optimization Group (ProdOps)
TOPS Personnel (Notify_TOps East)
Additional Transmission Personnel (NOTIFY_EHV Transmission Outages)
Transmission Reliability Compliance (TRELCOMP)
Protection & Control Engineering (PCAE_E)
Advanced Transmission Studies & Technologies (ATST)

[redacted] is defined as component of the [redacted]. In order to allow higher pre-contingency unit output, this scheme is utilized by operators such that a unit can manually be selected to [redacted]) on the [redacted]). [redacted] alarm points, indicating the status of each unit and the current trip condition are available for monitoring on the **LRSR** and **PI** displays.

**** ACTIONS FOR THE SCC RELIABILITY COORDINATOR TO TAKE ****

The SCC Desk will receive a single alarm of "[redacted]" when the [redacted] operates (Alarm points on the **LRSR** and **PI** displays will also change status accordingly). The SCC shall log the alarm in DOL and notify the following groups:

Columbus West TDC
PJM
Production Optimization Group (ProdOps)
TOPS Personnel (Notify_TOps East)
Additional Transmission Personnel (NOTIFY_EHV Transmission Outages)
Transmission Reliability Compliance (TRELCOMP)
Protection & Control Engineering (PCAE_E)
Advanced Transmission Studies & Technologies (ATST)

Refer to the Transmission Operations [redacted] located on the TOPS ShareNow **Engineering>Operating Guidelines>AEP East>IM** for further details.

Under Voltage Load Shed [redacted] in AEP/SPP and AEP/PJM Area

SWEPCO

[redacted]

A: SWEPCO [redacted] Scheme – Springdale Area Distribution

	Actual UVLS Station	Surrogate NERC MMWG PSSE Bus Name	Surrogate NERC MMWG PSSE BUS #	Surrogate NERC MMWG PSSE Voltage	[redacted] Monitored Voltage	Circuit Breaker	Voltage Setpoint	Actual Voltage [redacted]	Relay Time Delay	Circuit Breaker Interrupting Time	Overall Scheme Clearing Time	2017 Summer MWs In-service
NW Arkansas (Springdale Area)	[redacted]	[redacted]	[redacted]	69 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	8 cycles	188 cycles	8.45
	[redacted]	[redacted]	[redacted]	69 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	8 cycles	188 cycles	1.47
	[redacted]	[redacted]	[redacted]	161 kV	161 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	7.33
	[redacted]	[redacted]	[redacted]	161 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	8 cycles	188 cycles	10.39
	[redacted]	[redacted]	[redacted]	161 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	6 cycles	186 cycles	3.12
	[redacted]	[redacted]	[redacted]	161 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	7.67
	[redacted]	[redacted]	[redacted]	161 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	11.92
	[redacted]	[redacted]	[redacted]	161 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	2.64
	[redacted]	[redacted]	[redacted]	161 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	8.07
	[redacted]	[redacted]	[redacted]	161 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	9.14
	[redacted]	[redacted]	[redacted]	161 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	11.57
	[redacted]	[redacted]	[redacted]	161 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	13.88
	[redacted]	[redacted]	[redacted]	69 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	12.37
	[redacted]	[redacted]	[redacted]	69 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	4.05
	[redacted]	[redacted]	[redacted]	69 kV	12.0 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	9.45
	[redacted]	[redacted]	[redacted]	69 kV	12.5 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	10.26
	[redacted]	[redacted]	[redacted]	69 kV	12.5 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	4.75
	[redacted]	[redacted]	[redacted]	69 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	3.48
	[redacted]	[redacted]	[redacted]	69 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	16.44
	Total [redacted]											156.45

B: SWEPCO [redacted] Scheme – Texarkana Area Distribution

	Actual [redacted] Station	Surrogate NERC MMWG PSSE Bus Name	Surrogate NERC MMWG PSSE BUS #	Surrogate NERC MMWG PSSE Voltage	[redacted] Monitored Voltage	Circuit Breaker	Voltage Setpoint	Actual Voltage Trip Point	Relay Time Delay	Circuit Breaker Interrupting Time	Overall Scheme Clearing Time	2017 Summer MWs In-service
SW Arkansas (Texarkana Area)	[redacted]	[redacted]	[redacted]	69 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	4.67
	[redacted]	[redacted]	[redacted]	69 kV	69 kV	[redacted]	[redacted]	[redacted]	180 cycles	5 cycles	185 cycles	6.15
	[redacted]	[redacted]	[redacted]	69 kV	12.5 kV	[redacted]	[redacted]	[redacted]	180 cycles	3 cycles	183 cycles	6.96
	[redacted]	[redacted]	[redacted]	69 kV	12.5 kV	[redacted]	[redacted]	[redacted]	180 cycles	8 cycles	188 cycles	2.47
	Total [redacted]											20.25

[redacted] Under Voltage Load Shed [redacted]

C: Columbus Southern Power [redacted]– Southern Area

	[redacted] Station	[redacted] Monitored Voltage	Feeder	CB	Relaying	Priority	Voltage Setpoint	Relay Time Delay	Circuit Breaker Interrupting Time	Overall Scheme Clearing Time	2016 Summer MWs Interrupted
Adams/Seaman Area	[redacted]	[redacted]	[redacted]	22	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	4.23
	[redacted]	[redacted]	[redacted]	2	DPU2003	2	0.88 pu	180 cycles	3 cycles	183 cycles	3.94
	[redacted]	[redacted]	[redacted]	6	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	2.28
		[redacted]	[redacted]	8	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.04
	[redacted]	[redacted]	[redacted]	1	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	1.85
		[redacted]	[redacted]	2	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.98
	[redacted]	[redacted]	[redacted]	5	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.12
		[redacted]	[redacted]	3	SEL351S	2	0.88 pu	180 cycles	3 cycles	183 cycles	2.54
	[redacted]	[redacted]	[redacted]	2	SEL351S	3	0.88 pu	180 cycles	2.7 cycles	182.7 cycles	2.13
		[redacted]	[redacted]	4	SEL351S	3	0.88 pu	180 cycles	2.7 cycles	182.7 cycles	4.84
	[redacted]	[redacted]	[redacted]	41	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	7.36
		[redacted]	[redacted]	42	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	6.56
	Total [redacted]										45.87

	[redacted] Station	[redacted] Monitored Voltage	Feeder	CB	Relaying	Priority	Voltage Setpoint	Relay Time Delay	Circuit Breaker Interrupting Time	Overall Scheme Clearing Time	2016 Summer MWs Interrupted
Chillicothe Area	[redacted]	[redacted]	[redacted]	K	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	4.01
			[redacted]	F	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.57
	[redacted]	[redacted]	[redacted]	N	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	10.97
			[redacted]	M	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	10.
			[redacted]	P	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	9.3
			[redacted]	H	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	4.64
	[redacted]	[redacted]	[redacted]	C	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.53
			[redacted]	B	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.6
	[redacted]	[redacted]	[redacted]	1	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	5.04
			[redacted]	2	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	5.1
	Total UVLS Load Shed										59.76

[redacted].

Plant Fault Duty Procedures

A. PSO – Riverside Power Station

a. If Riverside Power Station large units (1 and 2) are both running AND one (or both) of the Riverside Station small peaker units (3 and/or 4) is running then open the 138 kV side of one of the two 345/138 kV autotransformers (via breaker 1301A or 1305A) to prevent the breaker(s) over duty issues. Reclose the breaker once the condition above ends**.**

B. OHIO - Cardinal 1

a. To prevent exceeding the fault duty current capability on the 138kV bus circuit breakers at Tidd whenever Cardinal Unit 1 is on line, the Tidd 138kv series reactor needs to be in service (R1 open) and

i. Close 138kV CB M2 at Tidd.

ii. Refer to the TiddOperatingMemo.pdf on the TOPS ShareNow at Engineering>Operating Guidelines>AEP East>OPCO for additional information.

Geomagnetic Disturbance Operating Procedure

Geomagnetic storms can cause large fluctuations in the earth's magnetic field. During these storms, geomagnetic induced current (GIC) is produced in the electric power system. The GIC flow through the power system via the neutral grounding points of the wye connected transformers, which can result in saturation of the transformer cores. Transformer saturation causes the excitation current to rise sharply. An increase in the excitation current usage of a transformer may be noticed as an increase in the lagging VAR usage of the transformer. This increase in lagging VAR usage can lead to system reactive power deficiencies and voltage problems.

Highlights of Procedures:

In this procedure, the SCC interacts with the PJM / SPP Reliability Coordinators while the Corpus TDC interacts with the ERCOT Reliability Coordinator.

AEP's GMD procedure:

1. Ensures the SCC and Corpus TDC are aware of GMD space weather forecast information
2. Provides guidance on a response to the potential GMD event;
3. Includes voltage monitoring which is a proxy for the Loss of Reactive Power Support;
4. Provides options to reduce the risk of damage to transformers with DC neutral current monitoring;
5. Has procedures addressing PJM member actions requirements;
6. Has procedures addressing SPP requirements;
7. Has procedures addressing ERCOT requirements; and
8. Conditions for terminating the GMD procedure.

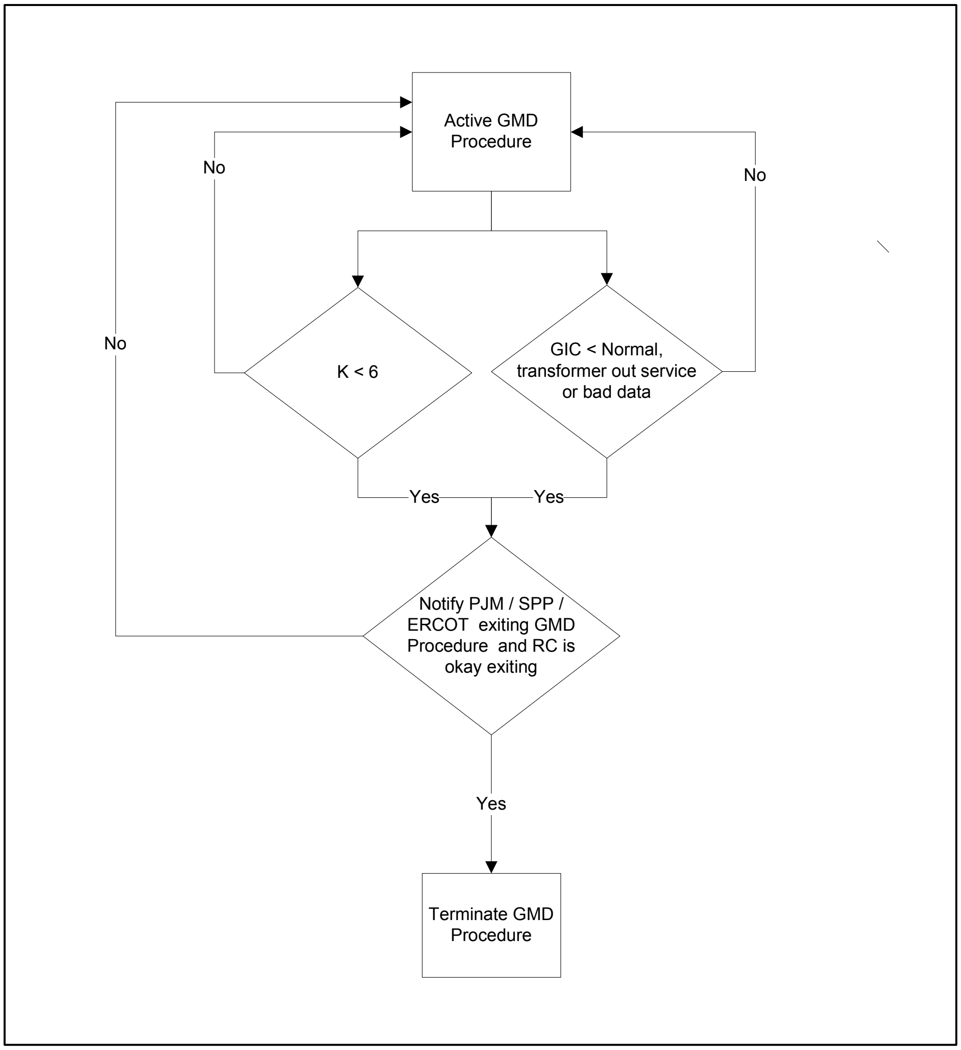
Typically when the K-index reaches a value of 7 or higher, there may be noticeable effects of the power system, such as:

- Unusual noises from power transformers
- Overheating in transformers
- Real and reactive power swings
- Tripping of capacitor banks
- Voltage fluctuations
- Large reactive consumption from transformers with saturated cores
- Operation or the non-operation of protective relays
- Negative sequence relays alarmed (Rockport)
- Communication system problems
- Large reactive consumption from transformers with saturated cores.

The SCC/Corpus Christi TDC receives K-index Alerts and Warnings from PJM, SPP, ERCOT, RCIS, or the Space Weather Prediction Center at the National Oceanic and Atmospheric Administration (NOAA). The TDISPATCHCCR, TOPSEAST and TOPSWEST inbox has been signed up to receive K-index Alerts and Warnings of 6 or higher. The GMD procedure specifies actions to follow for K-index Events.

The SCC monitors the transformer DC neutral Amps at select locations on the PI display board. If the transformers DC neutral Amps reach a threshold value for 10 minutes or more that could jeopardizes the transformer, the GMD procedure specifies actions to mitigate the risk to the transformer. SCC communicates to the Corpus Christi TDC any locations that have reached the threshold level on a similar parallel of any portion of the AEP ERCOT region.

The SCC and / or Corpus Christi TDC will terminate the active GMD Operating Procedure when the following have occurred.



Refer to “GMD Operating Procedure” guide located on the TOPS ShareNow at Engineering>Operating Guidelines> AEP System Wide Guidelines and Information for specific details.

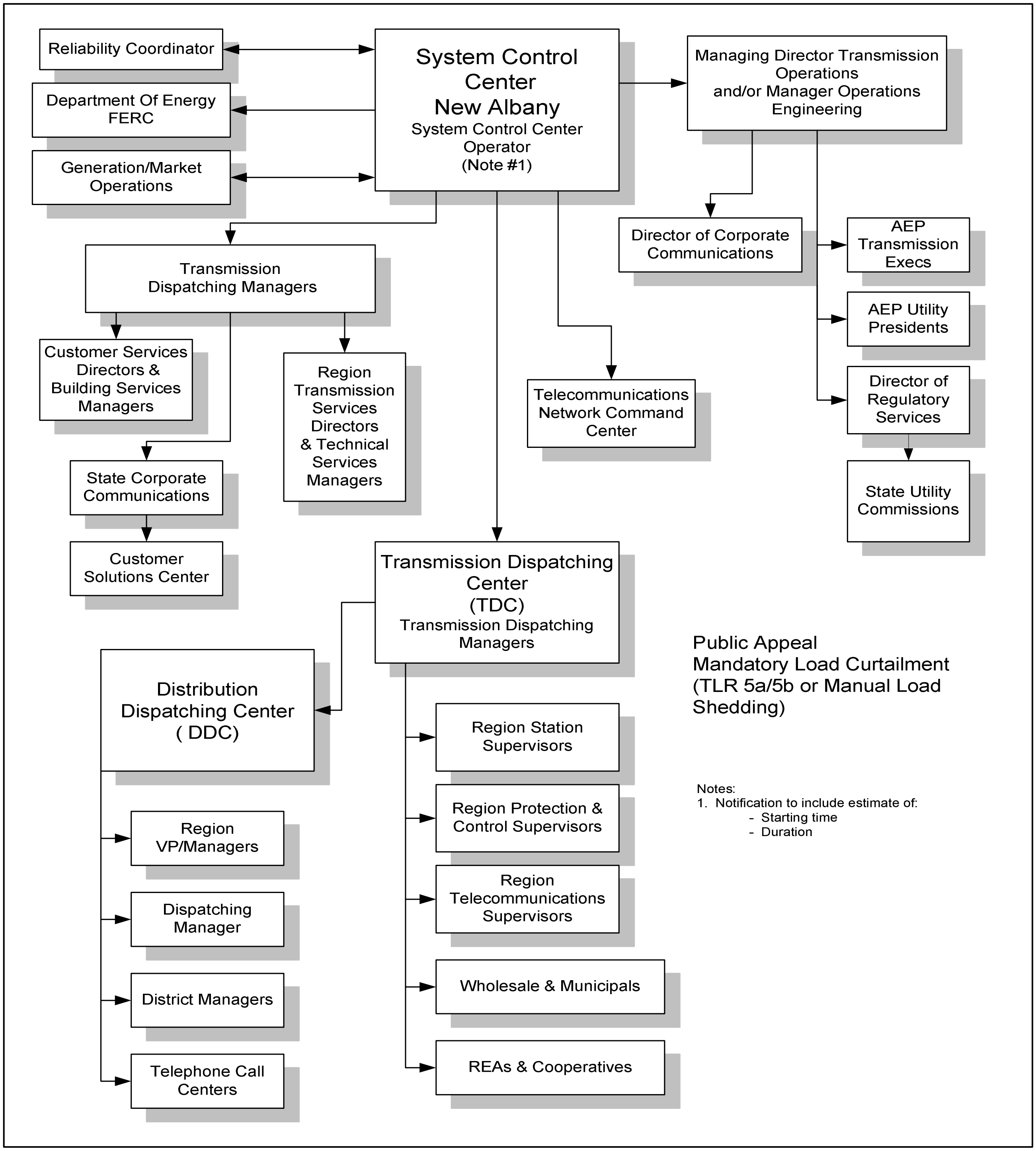


Figure VI-1
Transmission Emergency Notifications

NERC Transmission Loading Relief (TLR) Procedure

The NERC Transmission Loading Relief (TLR) Procedure is an Eastern Interconnection-wide procedure to allow the Reliability Coordinator to:

- Respect Transmission Service reservation priorities, and
- Mitigate potential or actual limit violations.

TLR Level	Reliability Coordinator Action	Comments
1	**Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL)violations.	
2	**Hold** Transfers at present level to prevent SOL or IROL violations.	Of those transactions at or above the Curtailment Threshold, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held.
3a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service.	Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the Reallocation process. See Attachment 1 to IRO-006, Section 2.3 and Section 6.0.
3b	**Curtail** Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation.	Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.4 and Section 7.0.
4	**Reconfigure** transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.	There may or may not be an SOL or IROL violation. There are special considerations for handling Interchange Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.5.
5a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point.	Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced ("pro rata") level. Pro forma tariff also requires curtailment/REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.6 and Section 6.0.
5b	**Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation	Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.7.
6	**Emergency Procedures**	Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding. See Attachment 1 to IRO-006, Section 2.8.
0	**TLR Concluded**	**Restore** transactions.

Figure VI-2 Transmission Loading Relief (TLR) Procedures

Unless explained otherwise, "curtailment" refers to those INTERCHANGE TRANSACTIONS with a 5% or greater DISTRIBUTION FACTOR on the CONSTRAINED FACILITY.

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to the Open Access Transmission Tariff (OATT).

Priority Table

Priority 0	Non-Firm Next Hour Market Service - NX
Priority 1	Non-Firm Service over secondary receipt and delivery points – NS
Priority 2	Non-Firm Hourly Service – NH
Priority 3	Non-Firm Daily Service – ND
Priority 4	Non-Firm Weekly Service – NW
Priority 5	Non-Firm Monthly Service – NM
Priority 6	Non-firm imports for native load and network customers from sources not designated as network resources – NN
Priority 7	Firm Point to Point Service – F and Network Integration Transmission Service from Designated Resources FN

NERC "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels" document list examples of possible system conditions for each TLR level.

TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. Analysis shows that holding new and increasing non-firm Interchange Transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. Analysis shows that full or partial curtailment or reallocation[1] of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour Analysis shows that full or partial curtailment or reallocation[2] of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. Analysis shows that full curtailment of non-firm Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. Analysis shows that the following actions can prevent exceeding the SOL or IROL: • Full curtailment non-firm Interchange Transactions and energy flows, and • Reconfiguration of the transmission system, if possible, and • Full or partial curtailment or reallocation[3] of firm Interchange Transactions and energy flows.
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment of non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible, and ▪ Full or partial curtailment or reallocation[4] of firm Interchange Transactions and energy flows.
TLR-6	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.
TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated

Additional PJM Emergency Procedures

PJM – Thermal Operating Guides

(Excerpts from PJM Transmission Operations M03 and Emergency Manual M13) Additional details may be found in specific operating memos outlined above.

Thermal Limit Exceeded	Corrective Actions	Time to Correct
Normal Rating (Actual flow greater than Normal Rating but less than Emergency Rating)	Non-cost actions, off-cost actions, emergency procedures except load shed.	Correct in 15 minutes, load shed is not used
Emergency Rating (Actual flow greater than Emergency Rating but less than load Dump Rating)	All of the above plus shed load to control flow below Emergency Rating.	Within 15 minutes of violation (Note #2)
Load Dump Rating (Actual flow greater than Load Dump Rating)	All of the above plus shed load to control flow below Emergency Rating.	Within 5 minutes of exceedance (Note 1) (Note 3)

Figure VI-3 Actual Overload Thermal Operating Guides

Note 1: For unplanned load shed events, TO must initiate load dump action within 5 minutes after PJM issues a Load Shed Directive. TO must not exceed the time based duration of any emergency rating/load dump rating.

Note 2: TOs have the option of providing STE limits that are at least 30-minutes in duration. The STE rating allows the time before load shed to be extended provided the actual flow does not exceed the STE rating. If the actual flow is above the LTE but below STE, load must be shed within the times indicated in Attachment F (PJM m03) for the facility, if other corrective actions were not successful.

Note 3: Dump load once to get below Emergency Rating within 5 minutes.

Thermal Limit Exceeded	If Post-Contingency simulated loading Exceeds Limit	Time to Correct
Normal	Trend – continue to monitor. Take non-cost actions to prevent contingency from exceeding emergency limit	N/A

Emergency	**Use all effective actions and emergency procedures except load shed.**	**30 minutes**
Load Dump	**All of the above however, shed load only if necessary to avoid post-contingency cascading.**	**30 minutes**

Figure VI-4 Post Contingency Simulated Thermal Operating Guide

Legend
Non-Cost
Off-Cost
Load Shedding

Note: System readjustment should take place within 30 minutes. PCLLRW should be implemented as post-contingency violations approach 60 minutes in duration. However, PCLLRW can be issued sooner at the request of the Transmission Owner or if the PJM Dispatcher anticipates controlling actions cannot be realized within 60 minutes due to longer generator start-up + notification times.

Voltage Limit Violations

Voltage Limit Exceeded	If Actual voltage limits are violated	Time to Correct
Normal High	Use all effective non-cost and off-cost actions.	Within 15 minutes
Normal Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except Load Shed Directive.	Within 15 minutes, load shed is not used.
Emergency Low	All of the above including Load Shed Directive if voltages are decaying.	Within 5 minutes
Load Dump Low	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Immediate
Pre-Contingency Transfer Limit Warning Point (95%)	Use all effective non-cost actions. Prepare for off-cost actions. Prepare for emergency procedures except Load Shed Directive.	Not applicable
Pre-Contingency Transfer Limit	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Within 15 minutes or less depending on the severity

Figure VI-5 Actual Voltage Limit Violations

Voltage Limit Exceeded	If post contingency simulated voltage limits are violated	Time to Correct
Emergency High	Use all effective non-cost actions.	Within 30 minutes
Normal Low	Use all effective non-cost actions.	Not applicable
Emergency Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except Load Shed Directive.	Within 15 minutes, load shed is not used.
Load Dump Low	All of the above including Load Shed Directive* if analysis indicates potential for voltage collapse.	Within 5 minutes

Voltage Drop Warning	Use all effective non-cost actions.	Not applicable
Voltage Drop Violation	All effective non-cost and off-cost actions including Load Shed Directive* if analysis indicates potential for voltage collapse.	Within 15 minutes
Post-Contingency Transfer Limit Warning Point (95%)	Use all effective non-cost actions. Prepare for off-cost actions. Prepare for emergency procedures except Load Shed Directive.	Not applicable
Post-Contingency Transfer Limit	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Within 15 minutes or less depending on the severity

Figure VI-6 Post Contingency Simulate Voltage Limit Exceeded

Heavy Load, Low Voltage Conditions (PJM Manual 13 - Section 5)

The following may be used to supplement other existing procedures when system loads are heavy and bulk power voltage levels are, on an anticipated or actual basis, at or approaching undesirable low levels. These procedures consist of the following:

- Low Voltage Alert
- Heavy Load Voltage Schedule Warning
- Heavy Load Voltage Schedule Action

<u>Low Voltage Alert</u>
The purpose of the Low Voltage Alert is to heighten awareness, increase planning, analysis, and preparation efforts when heavy loads and low voltages are anticipated in upcoming operating periods. PJM will issue this alert to members (Generation and Transmission) when projections show these conditions are expected. This Alert can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of Control Zone(s).

- PJM will conduct power flow analysis of the impact of future load and transfer increases upon the PJM system. Using this forward analysis, evaluation and planning will take place; including ensuring any reasonable necessary off-cost generation is ready to respond to anticipated transfer constraints. In this evaluation, consideration will also be given to changing the Reactive Transfer back-off limit from its normal value of 50 MW to 300 MW (interface dependent). If the decision is made to implement this measure, PJM will continually reassess the impact of this change on operations. .
- PJM will review generation and transmission outages (internal and external) and their impact on projected voltage problems.
- PJM will assess the impact of transfers and be prepared to rapidly identify any curtailable transactions that are adversely impacting reactive transfer limits.
- Using the NERC Interchange Distribution Calculator (IDC), PJM will assess the impact of parallel flows on its own facilities and transfer limits. If these flows are seen to be significant, PJM will be prepared, prior to dumping load, to invoke the NERC Transmission Loading Relief (TLR) process to provide relief from these parallel flows. .
- PJM will enhance reactive reporting from members by requesting a Reactive Reserve Check (RRC). (Also see PJM Manual M14D: Generator Operational Requirements, Attachment D: PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures.)
- PJM will enhance communications among SOS Transmission members via conference calls to discuss the status of critical equipment, voltage trends, and possible corrective actions.
- PJM dispatcher cancels the alert, when appropriate.
- SCC/MO notify their management and advise all stations and key personnel.
    - Transmission / Generation dispatchers ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted. Any monitoring or control maintenance work that may impact operation of the system is halted.
- SCC/MO to respond to PJM Reactive SSR by checking status and availability of all critical reactive resources. This includes polling generating stations of their reactive capabilities and the status of automatic voltage regulators. Any deviations or deficiencies of any equipment's reactive capabilities from what is modeled in the PJM EMS must be reported to PJM Power Dispatch.

Heavy Load Voltage Schedule Warning

A Heavy Load Voltage Schedule Warning is issued to members via the ALL-CALL system (Generation and Transmission) to request members to prepare for maximum support of voltages on the bulk power system. This Warning can be issued for entire PJM RTO, specific Control Zone(s) or a subset of Control Zone(s).

- Four hours prior to requesting the actual implementation of the Heavy Load Voltage Schedule, PJM may give advance notice to members of the upcoming need for this schedule. At that time, members will be requested to verify that all actions have been taken on the distribution and sub-transmission systems to support the voltage at the EHV level.
- PJM dispatcher cancels the Heavy Load Voltage Schedule Warning, when appropriate.
- SCC while observing established limits should ensure that where possible, all underlying reactors are out of service, all capacitors on the underlying system are in service, and transformer taps are adjusted to ensure distribution capacitors are in-service.
- MO should ensure all unit voltage regulators are in service.

Heavy Load Voltage Schedule

A Heavy Load Voltage Schedule is issued to members (Generation and Transmission) at peak load periods via the ALL-CALL system to request maximum support of voltages on the bulk power system and increase reactive reserves at the EHV level. This Action can be issued for entire PJM RTO, specific Control Zone(s) or a subset of Control Zone(s).

- PJM at peak load period, request all companies implement the Heavy Load Voltage Schedule via the ALL-CALL system.
- PJM dispatcher cancels the Heavy Load Voltage Schedule, when appropriate.
- SCC while observing established limits should ensure that where possible, all reactors are out of service, all capacitors on the underlying system are in service, capacitors at the EHV level with PLC's are in service where required.
- MO should ensure all unit voltage regulators are in service.
- SCC should ensure all units on the EHV are at there normal schedule
- Impacted Transmission / Generation dispatchers should ensure all units connected at the EHV level are operated so that reasonable MVAR reserve is maintained as determined by real-time monitoring tools or good engineering judgment. Reactive moves on these units should be coordinated through the PJM Power Dispatcher
- SCC should ensure all units on the 230 kV system and below should increase MVAR output as necessary to maintain designated bus voltage schedules.
  - Attempt to have units run at the high end of their voltage schedule; i.e. if the voltage schedule is 1.009, and the top band is 1.014, have units operate at this level.
  - If higher than scheduled voltages are required, increase voltage schedules in 1 volt increments until voltage conditions improve, or a Max. Mvar limit is reached.
- Generating units should notify the TDC when they are approaching any reactive limits
- TDC should notify SCC of any units approaching reactive limits

- SCC should keep the PJM Power Dispatcher informed of any units approaching maximum MVAR output, any abnormal unit MVAR restrictions, and any voltage regulators that are out of service.

Post Contingency Local Load Relief Warning (PJM Manual 13 - Section 5.4)

The purpose of the Post Contingency Local Load Relief Warning (PCLLRW) is to provide advance notice to a transmission owner(s) of the potential for load shed in their area(s). It is issued after all other means of transmission constraint control have been exhausted or until sufficient generation is on-line to control the constraint within designated limits and timelines as identified in PJM Manual 3 Transmission Operations, Section 2 –Thermal Operating Guidelines.
The AEP PCLLRW-PCAP Procedure document has specific procedures to determine the course of action to mitigate the overloads/undervoltage if the identified outage was to occur for a PCLLRW. The actions could include system reconfiguration and /or load shed. The AEP procedures follow the PJM Member Actions in Section 5.4 of M-13.

The Post Contingency Action Plan (PCAP) in the AEP PCLLRW-PCAP Procedure document is utilized in the SPP footprint. SPP BA Emergency Operating Plan section 6.4 addresses the issue of load shedding.. The PCLLRW and PCAPs can be issued for branch or voltage contingencies. The actions could include system reconfiguration and /or load shed.

Please refer to PCCLLRW-PCAP Procedure document located on the TOPS ShareNow at **>SCC>SCC – All Inclusive>PCLLRW-PCAP Rev 6** for additional information.

Post-Contingency Load Dump Limit Exceedance Analysis (PJM Manual 13 Section 5.4.1)

If the post-contingency flow were to exceed the 15-minute Load Dump rating, there is a concern that the facility may trip before actions could be implemented to reduce the flow within limits. To prepare for this potential N- 2 (initial contingency plus the overloaded facility) and prevent a cascade, PJM will perform up to an N-5 analysis on facilities over 115% of their 15-minute Load Dump rating.More details are located in PJM Manual-13: Emergency Operations

Complete details of the switching solution process are available in PJM Manual-03: Transmission Operations.

For AEP Transmission Operations' specific response to PCLLRWs issued by PJM, please see the PCLLRW-PCAP Procedure document noted previously.

PJM Reactive Reserve Check (RRC) (PJM Manual 14D Attachment D)

Upon the request of PJM, The System Control Centers (SCC) will provide a "Reactive Reserve Check" report to PJM. This report filled out in the eDart RRC form will include the following information within the Transmission Owners zone: Refer to our MVARS display on the ADXfg - SCC machine for the desired values.

This report will include the following information within the Transmission Owner's zone:

- Unit MVAR Reserve (The sum of the differences between the present operating points, leading or lagging, and the lagging MVAR capability of all synchronized units.)
- Lagging MVAR Reserve (The sum of the lagging MVAR capability of all on-line condensers and Static Var Compensators.)
- Transmission Capacitor/Reactor MVAR Reserve (The sum of the nameplate MVAR values of capacitors that are capable of being energized or reactors that can be removed from service.) **Note**: The first two items require open dialogue between the Transmission Owner and the Generation Owners within the Transmission Owner's footprint.
- PJM will make the report available to Local Control Centers.

PJM Reactive Reserve Check (RRC)			
Transmission Owner	Unit MVAR Reserve	Lagging MVAR Reserve	Transmission Capacitor/ Reactor Reserve
PJM TOTAL			

Units equipped with [redacted]

Plant Name (Station Name)	Unit No.	Summer Net Real Power Capability	PSS/E Bus Name	PSS/E Unit ID	Status
AEP-RFC[1]					
Anderson CT	3	75	05ANDCT	3	
Ceredo (Twelve Pole Creek)	1	80	05TWELVE	1	
Ceredo (Twelve Pole Creek)	2	80	05TWELVE	2	
Ceredo (Twelve Pole Creek)	3	80	05TWELVE	3	
Ceredo (Twelve Pole Creek)	4	80	05TWELVE	4	
Ceredo (Twelve Pole Creek)	5	80	05TWELVE	5	
Ceredo (Twelve Pole Creek)	6	80	05TWELVE	6	
Conesville	4	775	05CVG4	4	Not Activated
Conesville	5	400	05CVG5	5	
Conesville	6	400	05CVG6	6	
Foothills (Baker)	1	167	20FOOTHL	1	
Foothills (Baker)	2	167	20FOOTHL	2	
Hanging Rock (Cornu)	1A	175	05CORNU	1A	
Hanging Rock (Cornu)	1B	175	05CORNU	1B	
Hanging Rock (Cornu)	1S	250	05CORNU	1S	
Hanging Rock (Cornu)	2A	175	05CORNU	2A	
Hanging Rock (Cornu)	2B	175	05CORNU	2B	
Hanging Rock (Cornu)	2S	250	05CORNU	2S	
Lawrenceburg	G1	560 total	05LAWBG1	1A	
Lawrenceburg	G2		05LAWBG1	1B	
Lawrenceburg	S1		05LAWBG1	1S	
Lawrenceburg	G3	560 total	05LAWBG2	2A	
Lawrenceburg	G4		05LAWBG2	2B	
Lawrenceburg	S2		05LAWBG2	2S	
R.P. Mone	1	170	05CONVOY	1	
R.P. Mone	2	170	05CONVOY	2	
R.P. Mone	3	170	05CONVOY	3	
Riverside (Zelda)	1	167	20ZELDA	1	
Riverside (Zelda)	2	167	20ZELDA	2	
Riverside (Zelda)	3	167	20ZELDA	3	
Rockport	1HP	666	05RKG1	1H	
Rockport	1RH	654	05RKG1	1R	
Rockport	2HP	656	05RKG2	2H	
Rockport	2RH	644	05RKG2	2R	
Rolling Hills (Flatlick)	1	170	05FLTLCK	1	
Rolling Hills (Flatlick)	2	170	05FLTLCK	2	
Rolling Hills (Flatlick)	3	170	05FLTLCK	3	
Rolling Hills (Flatlick)	4	170	05FLTLCK	4	
Rolling Hills (Flatlick)	5	170	05FLTLCK	5	
Washington (Beverly)	1A	175	05BEVERL	1A	
Washington (Beverly)	1B	175	05BEVERL	1B	
Washington (Beverly)	1S	250	05BEVERL	1S	
Waterford	GT1	810 total	05WATERF	1A	
Waterford	GT2		05WATERF	1B	

Plant Name (Station Name)	Unit No.	Summer Net Real Power Capability	PSS/E Bus Name	PSS/E Unit ID	Status
Waterford	GT3		05WATERF	1C	
Waterford	ST1		05WATERF	1S	
AEP-SPP					
East Texas Co-gen (Eastex Switching via North Texas Eastman)	G1	178.5	ESTGAS1	1	
East Texas Co-gen (Eastex Switching via North Texas Eastman)	G2	178.5	ESTGAS2	1	
East Texas Co-gen (Eastex Switching via North Texas Eastman)	S1	128	ESTSTM1	1	
Gateway (Tenaska Switch)	G1	179	TENGAS	1	
Gateway (Tenaska Switch)	G2	179	TENGAS	1	
Gateway (Tenaska Switch)	G3	179	TENGAS	1	
Gateway (Tenaska Switch)	S1	400	TENSTM	1	
Green Country (Riverside)	G1	183	COGEN G1	G	
Green Country (Riverside)	S1	115	COGEN S1	S	
Green Country (Riverside)	G2	183	COGEN G2	G	
Green Country (Riverside)	S2	115	COGEN S2	S	
Green Country (Riverside)	G3	183	COGEN G3	G	
Green Country (Riverside)	S3	115	COGEN S3	S	
Harrison County (Lebrock)	G1	211	LEBROCG1	1	
Harrison County (Lebrock)	G2	211	LEBROCG2	1	
Harrison County (Lebrock)	S1	275	LEBROCS1	1	
J.L. Stall	6A	153	ARSHILL2	G1	
J.L. Stall	6B	153	ARSHILL3	G2	
J.L. Stall	6S	187	ARSHILL4	S1	
Mattison	1	75	MATISN-1	1	
Mattison	2	75	MATISN-2	1	
Mattison	3	75	MATISN-3	1	
Mattison	4	75	MATISN-4	1	
Northeastern (Northeast Gas)	1A	150	NES1-1A	1	
Northeastern (Northeast Gas)	1B	150	NES1-1B	1	
Oneta	S1	255	OECSTM1	1	
Oneta	G1-1	175	OECGT1-1	1	
Oneta	G1-2	175	OECGT1-2	1	
Oneta	S2	255	OECSTM2	1	
Oneta	G2-1	175	OECGT2-1	1	
Oneta	G2-2	175	OECGT2-2	1	
Riverside	3	73	RSS NG3	1	
Riverside	4	73	RSS NG4	1	
Southwest	4	71	SWS NG4	1	
Southwest	5	71	SWS NG5	1	
Turk	1	600	TURKCOAL	1	

The Voltage_and_Reactive_Guide_AEPE_AEPW-SPP contains [redacted] which resides on the AEP TOPS ShareNow at **Engineering>Operating Guidelines>AEP System Wide Guides and Information>Voltage and Reactive Guides.**

Conservative Operation

The need to operate the SPP/PJM RTO, the AEP West Control Area, and the AEP East Control Zone more conservatively can be triggered by any number of weather, environmental, terrorist, or computer events, including:

- forest fires/brush fires that threaten major transmission circuits
- extreme weather-related events, such as ice/snow/wind storms,serverly cold / hot weather, hurricanes, tornadoes, severe thunderstorms, and floods
- environmental alerts
- terrorist alerts
- solar magnetic disturbance events
- widespread fuel related emergencies
- failure of Energy Management System (EMS)/Control Area CAMS computers.

During conservative operations, SPP/PJM Reliability Coordinator may reflect conservative transfer limit values, select double-contingencies for review, and/or evaluate maximum credible disturbances.

- SPP/PJM Reliability Coordinator has the authority to reduce transfers into, across, or through the SPP/PJM RTO or take other actions, such as cost assignments to increase reserves and reduce power flows on selected facilities.
- It is SPP/PJM Reliability Coordinator's responsibility to analyze the reliability of the SPP/PJM RTO and determine if it is in jeopardy. If required, operations planning branch staff are called upon to develop revised limitation curves.
- SCC transmission dispatchers, MO generation dispatchers and MO/PJM marketers respond, as required, to specific requests and Operating Instructions of the SPP/PJM Reliability Coordinator subject to the constraints noted in the Operator Responsibility and Authority to Act document in Appendix VI.
- SCC engineering personnel to provide support to transmission dispatchers.

AEP continuously monitors operating limits to ensure reliability following the next anticipated contingency. An unknown operating state would be declared under the following conditions:

A. The AEP State Estimator Real Time Network (RTNET) or Real Time Contingency Analysis (RTCA) solutions are invalid/unavailable or the Control Area CAMS computers fail and the applicable SPP/PJM/ERCOT RC EMS analysis tools are also invalid/unavailable concurrently with the AEP analysis tools.

B. The AEP State Estimator RTCA routine fails to solve for a particular contingency and the applicable SPP/PJM/ERCOT RC EMS analysis tools are also invalid/unavailable concurrently with the AEP analysis tools. Additional information regarding AEP practices for defining the scope of contingencies defined for real-time security analysis in the AEP State Estimator may found in the Business Practice of Defining Contingencies in ALSTOM State Estimator document.

System conditions change such that the next anticipated contingency falls outside the scope of the known special stability study parameters for certain Generation facilities across the AEP footprint.

Refer to the "Operating in an Unknown State" procedure located on the TOPS ShareNow >Engineering>Operating Guidelines> AEP System Wide Guidelines and Information area for more detailed information.

Emergency Messages

Samples of messages to be broadcast in affected areas and procedures for communicating transmission emergencies are included in Figures VI-7 through VI-10. Messages will be modified as necessary to convey the nature of the problem and the extent of the area affected.

This is an Emergency Message from American Electric Power Company

Location, Date –A serious electric transmission constraint is anticipated *today/tomorrow*, *Day, Date* as a result of the extremely *hot* weather.

To help ease this problem AEP urges all its customers in homes, factories, stores and everywhere in *Districts Affected,* to reduce their usage of electric power in every possible way, during the hours of 7AM through 9PM on *Day, Date*. Please avoid using such appliances as clothes washers, dishwashers, clothes dryers and ranges; turn off unnecessary lighting; and turn up the thermostat for air conditioning or turn off the air conditioning. Cooperation in reducing the demand for electricity during daylight hours all day will help prevent interruption of electric service.

AEP will keep customers informed with public announcements until this transmission constraint eases.

Energy Conservation Tips:

- Set the thermostat between 78 and 80 degrees and operate ceiling fans for additional comfort with raised temperatures.
- Draw drapes and close blinds to help cool the home.
- Turn off unnecessary lights.
- Turn off all non-essential equipment and appliances.
- Reduce hot water consumption
- Limit opening refrigerators and freezers.
- Limit water consumption if you are on well water.
- Limit use of kitchen appliances, dishwashers, ranges, etc.
- Avoid using washers and dryers

AEP appreciates the patience and cooperation of our customers during this extreme heat wave. Please cooperate now by reducing your use of electricity. By doing this, you can help prevent possible interruptions in your electric service. AEP will continue to keep you informed with public announcements until this problem eases and we thank you for your cooperation.

Figure VI-7
Voluntary Load Curtailment Initiation Announcement to the Public

This is an Emergency Message from American Electric Power Company.

A serious electric transmission constraint has developed as a result of (*unprecedented cold weather, unprecedented hot weather*).

To avoid uncontrolled blackouts it has become necessary to interrupt electric service to customers for periods ranging from ten minutes to two hours. To minimize inconvenience, the interruptions will take place on a rotating basis; while some areas will be off, others will be on. Later, the areas of outages will be reversed, so that no group of customers will have to bear all of the inconvenience.

When service is restored in your house, you can help AEP hasten the job by turning off all appliances, lights, radios, stereos, and television sets that were in use at the time the electricity went off. We recommend that you leave one low-watt electric light in the "on" position so that you'll know when the power has been restored.

AEP thanks you for your cooperation in helping us to get through this critical time.

Figure VI-8
Mandatory Load Curtailment Initiation Announcement to the Public

This is an Emergency Message from American Electric Power Company.

The power curtailment to AEP's customers is continuing. In an effort to make this situation as easy as possible for all customers, the company is alternating the power cut-off among groups of customers for periods ranging from ten minutes to two hours. Make sure that all appliances are turned off so that, when the power is restored, it will not cause an overload and create further problems. If you are receiving power, please keep your usage to a bare minimum. With everyone cooperating, the company hopes to be able to restore full service as soon as conditions permit.

AEP regrets that the critical problem it now faces has made these drastic steps necessary, and thanks all of its customers for their cooperation and understanding.

Further announcements will follow as the situation continues to develop.

Figure VI-9
Mandatory Load Curtailment Information Statement to the Public

This is a Message from American Electric Power Company.

AEP reports that the serious electric transmission constraint has now eased, and full-time electric service to its customers is being restored as quickly as possible.

While the power situation has improved enough to permit us to restore service, we ask you to continue to be careful in your power use. With your cooperation, we have come through this emergency in good shape, and we are grateful.

AEP thanks you.

Figure VI-10
Transmission Emergency Termination Statement to the Public

Section VII
Major Storm Restoration

> *No aspect of operations is more important than the health and safety of people. Our customers' needs are met in harmony with environmental protection.*

Introduction:

Super Storm Sandy, the June 2012 Derecho, the 2008 Hurricane Ike, and other big storms have brought a critical eye on the way utilities respond to large storms and other emergencies. Hurricane Ike is unique in that it impacted both the AEP West and AEP East areas. Initially the storm involved the AEP West SWEPCO area. The remnants of the storm then produced significant wind damage across the AEP East Ohio area.

As a result of the frequent large storm events, AEP developed the Emergency Response Plan to improve emergency response efforts. In addition, Transmission Operations has further developed several tools and process documents, such as the Outage Tracking System (OTS), the New Albany Transmission Operations Center Major Event Coordination document, and the TDC Storm Manual Tulsa Region, which align with the AEP Emergency Response Plan.

AEP Emergency Response Plan - Overview:

The AEP Emergency Response Plan (ERP - http://erp/) is a multi-year project to improve emergency response efforts within AEP and between Regulatory agencies and customers. The ERP project focuses on three key areas to improve AEP's emergency response:

1. Incident Command System (ICS) – ICS is a comprehensive approach to incident management. The management tool responds to both small and large emergencies.
2. Technology Deployment
    a. Outage Management System (OMS – http://OMS/)
    b. Enhanced Estimated Time of Restoration (ETR)
    c. Assessment and restoration processes.
3. Process Improvement – Improve the storm management structure and focus on assessment and restoration processes

ERP currently has 32 processes within the AEP ICS system. Each process is described in detail at the http://erp/ web page under the forms, checklist, procedures, and training materials area. A number of these processes are transmission specific and are listed below. Transmission Field Services (TFS) is the owner for the following transmission processes:

- ICS_Event_Level_Determination_-_Transmission_Process
- Transmission_Assessment_Process
- Transmission_Priority_Process

AEP ERP - Declaration of Transmission Emergency

One of the most important steps in the ERP is assessing the impact of the event and determining the severity of the event. For transmission related events, Transmission Field Services (TFS) and Transmission Operations (TOPS) play a key role in the initial event assessment. The ICS Event Level Determination – Transmission Process document contains a process flow chart to identify the event level to activate the appropriate transmission response. The response levels vary from I to V with I being the most severe.

A declaration of a Transmission Emergency will be determined by the TFS Managing Director and the TOPS Managing Director or their designees. Upon the declaration, the Directors will notify the VP's of AEP Transmission, as well as, the State Presidents of the emergency. The System Control Center Operator's will notify the Managing Directors of AEP Transmission, Corporate Communications, Network Command Center, Customer Services and the TDC's. The TDC's will notify Region Managers and the DDC's.

AEP ERP - Transmission Operations Overview:

Upon declaration of a Transmission Emergency, TOPS will utilize processes outlined in the Storm Restoration Plan below and as shown in the New Albany Transmission Operations Center Major Event Coordination document (located on TOPS Sharepoint>Emergency Plans>NATOC Major Event Coordination) and the TDC Storm Manual Tulsa Region (located on the TOPS Sharepoint at TDC>Tulsa>Emergency Plans>). These plans establish roles and responsibilities, and notification requirements during a major transmission event. Objectives include assessing the event, stabilizing the grid, restoring customers in a safe, efficient manner, and restoration of the grid to its original configuration. The TDC Unit Leader is part of the ICS structure and will be the liaison to ICS. The TDC Unit Leader must meet the training requirements defined by ICS.

TOPs will utilize the Outage Tracking System (OTS – http://ots/), which enhances communication between Transmission Dispatch, Distribution Dispatch, Transmission Field Services, and AEP management during major system events by providing a shared communication tool for the exchange of transmission outage information. OTS will be the catalyst for setting restoration priorities. The OTS program supports ICS during system events by allowing all approved AEP employees access to transmission and sub-transmission outage data via the OTS web page.

AEP ERP - Training Personnel

TOPS dispatch personnel, as well as applicable personnel throughout Transmission, have been trained in the ICS process. Additional ICS training manuals and links to the online training in KEY are listed on the http://erp/ web site under the References book icon and are available as needed. In addition, TOPS and Transmission Field Services Management are responsible for scheduling and training personnel on a regular basis so that the appropriate personnel are prepared to utilize the ICS structure and implement the Storm Restoration Plan when a major event occurs.

Storm Restoration Plan

THE KEY TO A SUCCESSFUL RESTORATION EFFORT IS IN THE EARLY ASSESSMENT OF THE EXTENT OF THE DAMAGES!

It is important to initiate the Storm Restoration Plan as soon as possible to ensure early assessment. The earlier the need for additional resources is identified, the sooner those resources can be mobilized and utilized in the restoration effort. However, as the outage situation worsens and the outage footprint expands, additional resources must be called upon to be involved in the restoration efforts. Communications with the various Coordination Centers will be facilitated by the use of Conference Bridges. As noted in the NATOC Major Event Coordination document, the Conference Bridge number(s) will be disseminated to all parties via text or email.

A. Restoration Priority

When a major outage emergency occurs, there is usually damage to the Company facilities at a number of locations. The removal of hazardous conditions has the highest priority. Maximum effort will then be placed in stabilizing the transmission grid to prevent the spread of outages to other areas not directly impacted by the storm. Once the transmission grid is stabilized, service to stations and customers will proceed as quickly and safely as possible with the primary effort being placed where the largest number of customers will be impacted.

Communicating accurate information in a timely manner during a major event is a critical component in the expedient restoration of the transmission system. The Outage Tracking System (OTS) will provide the communication interface between Transmission Dispatch, Distribution Dispatch and Transmission Field Services by providing multiple designated users the ability to input "real-time" data into a shared Web application. The shared Web application "**Data Entry Interface**" can be accessed by typing *http://ots/editor/* into the address bar of an internet access page.

The OTS program supports the ICS structure during system events by allowing all **approved** AEP employees access to transmission and sub-transmission outage data via the OTS web page. The web page gives users the ability to sort and research data. Data will include; Transmission outages, Distribution network circuit outages, affected stations, estimated assessment times (EAT), estimated field repair time (EFRT), estimated restoration times (ERT), trouble information, priority status (Station and Circuit/Equipment) and restoration rank. Please refer to the Outage Tracking System Guide -2015 users guide for additional information on the accessing the OTS system.

B. **Staffing**

The TDC Unit Leader and the SCC Lead Operator are responsible for allocating appropriate staff to manage the event. Additional staffing information is included in the NATOC Major Event Coordination document which also includes staffing responsibilities for Transmission Operations Engineering and State Estimator Support personnel. Transmission Operations management will also continually evaluate the staffing needs as the event progresses.

C. Communications

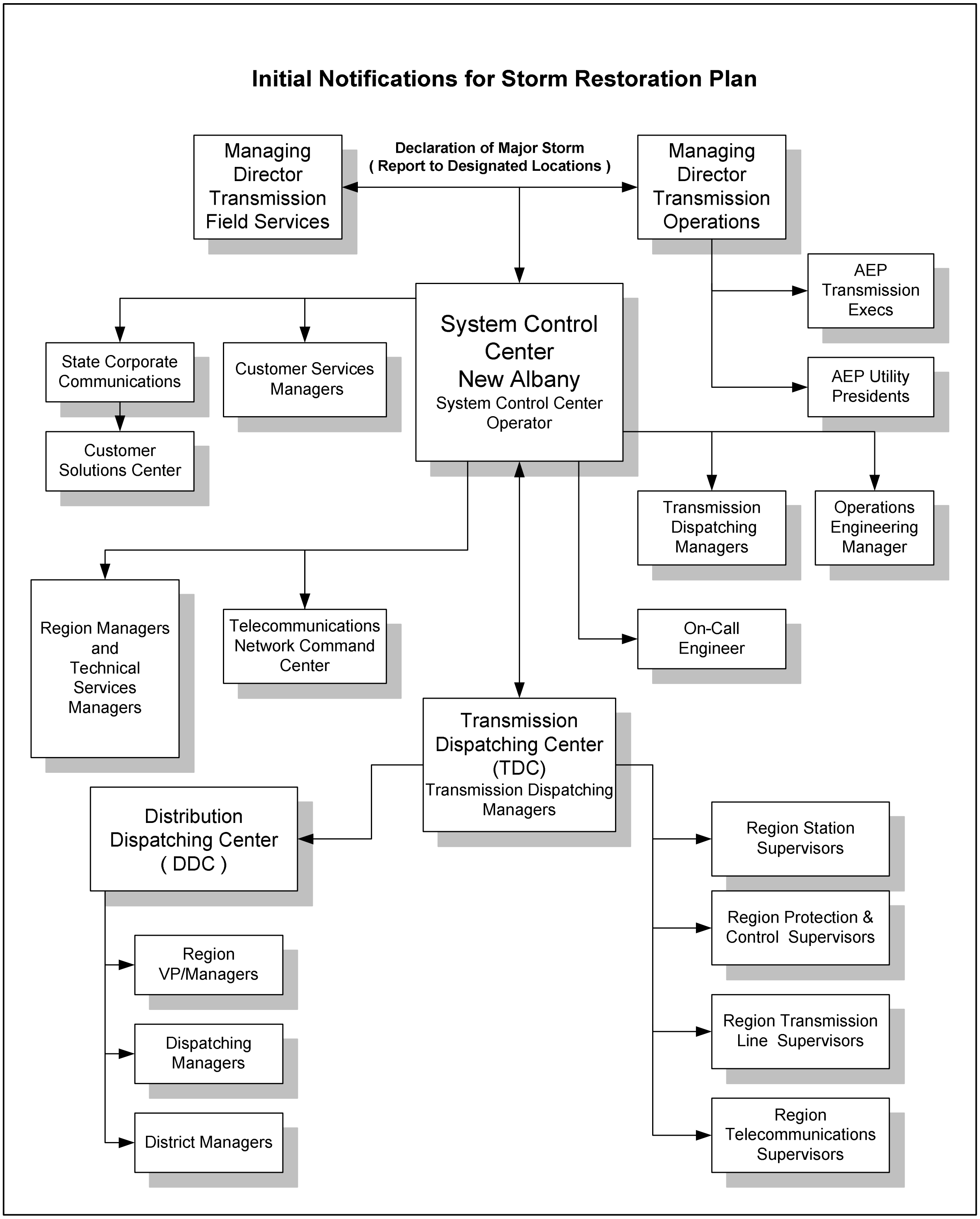


Figure VII-1

D. **Storm Organization Responsibilities**

Transmission Svcs. VP, Transmission Operations VP, Transmission Svcs.Region Directors, Transmission Operations Managers and personnel, T-Line supervision and engineers, Station Managers and engineers, P&C supervision, clerks and Distribution Operations.

Storm Titles	Description of Responsibilities	Likely Sources
Transmission Field Services (TFS)	1. Determine work priorities and convey them to the SCC. 2. Interface with state commissions via Regulatory Services, Corporate Communications, State Emergency Services, and all other outside entities. 3. Interface with Distribution Region management. 4. Receive damage assessments from the TFOps and the SCC. 5. Receive from the TFOps the manpower needs and equipment needs. 6. Obtain additional manpower and equipment to meet the needs of the TFOps. 7. Assign foreign crews to TFOps. 8. Set storm administrative policies. 9. Request Telecom. to call out personnel to reprogram radios. 10. Determine location for reprogramming 800 Mhz radios. 11. Determine the additional communication equip. required and request Telecom. to acquire. 12. Provide the TFOps with general data on incoming crews. 13. Arrange for line fault locating equipment. 14. Determine equipment that foreign crews should bring	Transmission Region Director and designees, Transmission Operations Managers and their designees, Distribution Operations representative

	with them. 15. Keep management informed and provide reports as required.	
Storm Titles	**Description of Responsibilities**	**Likely Sources**
System Control Center (SCC)	1. Inform the TFS of the status of facilities. 2. Assist the TFS in making work priorities. 3. Interface with Customer Services with regards to customer inquiries and obtain related info. from the TDCs. 4. Obtain info. from the TDCs on the status of company facilities. 5. Assist in informing Company Management. 6. Call in Operations Engineering	Transmission Operations Managers System Control Center Operators Engineering Support
Transmission Dispatch Center (TDC)	1. Dispatch crews. 2. Direct necessary switching. 3. Convey area and D-Region work priorities to SCC. 4. Receive damage assessment from crews. 5. Assign personnel to stations as needed. 6. Monitor location of crews. 7. Coordinate priorities with the DDCs and pass regional work priorities to the DDCs. 8. Convey equipment status to the DDCs and SCC. 9. Provide outage/restoration info. To the SCC at regular intervals. 10. Assign 800 Mhz radio storm emergency channels for Transmission work crews.	Dispatching Supervisors Dispatching Coordinators Transmission Dispatchers

Storm Titles	Description of Responsibilities	Likely Sources
Transmission Field Ops (TFOps)	1. Supply damage assessment and routine reports to TDCs and TFS. 2. Administer the administrative directives of the TFS. 3. Monitor crew progress and locations. 4. Receive damage assessments from crews. 5. Determine materials, equipment and manpower needs. 6. Provide food and lodging services. 7. Provide crew guides/scouts as needed. 8. Provide TDCs with detailed information about incoming crews. 9. Provide time keeping. 10. Establish work orders, answer phones, administer charge cards, supply employee handbooks.	T-Line Area supervision Station Area Managers P&C Area Supervision Clerks Material coordinators
Distribution Dispatching Center (DDC)	1. Direct switching on the distribution system from the feeder breakers out. 2. Coordinate work priorities with the TDCs. 3. Dispatch personnel in response to distribution alarms. 4. Provide reports on total customers outaged at regular time intervals. 5. Provide distribution equipment status to TDCs. 6. Work directly with the Customer Solutions Center to respond to customer outages. 7. Interface with critical customers such as those on life support systems.	Dispatching Managers Dispatching Supervisors Distribution Dispatchers

Storm Titles	Description of Responsibilities	Likely Sources
Field Crews	1. Provide damage assessments to TDCs and TFOps. 2. Determine equipment, materials and manpower needs and provide this information to TFOps and others as assigned. 3. Administer the administrative directives of the TFS. 4. Restore service to facilities as directed by the TDC. 5. Provide property owner damage assessments to TFOps. 6. Respond to property owner's damage. 7. Receive and conduct switching orders from the TDC. 8. Clear roads into stations. 9. Operate line fault locating equipment. 10. Maintain station batteries. 11. Assist Telecommunication to reach MW sites as requested. 12. Have all accident investigation forms	T-Line personnel P&C personnel Station personnel
Telecommunications	1. Lease cell phones. 2. Provide temporary communications equipment. 3. Provide communications equipment maintenance to include microwave sites. 4. Program 800 MHz radios for incoming crews at the designated location. 5. Provide hand held 800 MHz radios to field personnel as requested. 6. Provide outside maintenance services as required.	Telecommunication technicians

Storm Titles	Description of Responsibilities	Likely Sources
Customer Services	1. Respond to inquiries from customers. 2. Interface with the SCC\TDC with regard to restoration status. 3. Inform customers of estimated restoration times.	A person from Customer Services will be assigned to interface with their Field Engineers.
Shared Services	1. Provide 24 hours per day vehicle and stores services. Provide specialty permits for incoming crews.	Stores attendants Garage attendants
Corporate Communications	1. Act as the liaison between the TFS Directors, the outside media, and Government Organizations.	Corporate Communications
Customer Solutions Center	1. Respond to customer inquiries 2. Generate trouble tickets 3. Inform customers of estimated restoration times	Customer Solutions Center

These activities support the AEP Emergency Response Plan. The ICS structure is still being implemented in the APCO area.

E. **Storm Emergency Communications**

Sixteen storm channels have been created on the 800 MHz radio system for use by AEP East Transmission Operations during major storms. Emergency channels have been designated for each of the 5 dispatching areas (corresponds to dispatching desks) on the AEP East System as follows:

<u>Dispatching Area</u> <u>Storm Channels</u>

[redacted] - [redacted] - [redacted] - [redacted] [redacted]
- [redacted] - [redacted]

The TDC Storm Manual Tulsa Region indicates the Transmission Dispatcher in the Tulsa TDC and Shreveport TDC in the AEP West region will determine when the storm channels will be used during a transmission emergency.

The Transmission Dispatcher will determine when their assigned storm channel(s) will be used during transmission emergencies to increase communications within their dispatching area. It will be the responsibility of the Transmission Dispatcher to inform both the transmission crew supervisors working in his area, and the TFOps, when storm channels are to be used.

Each AEP East transmission vehicle with an 800 MHz radio will have 12 storm channels programmed on their radio and will be able to communicate via the radio sites in the normal area of use, plus as many radio sites as possible in the adjacent area(s). For example, vehicles in the Columbus Central and possibly Columbus West dispatching areas will likely be able to assist during emergencies in the Columbus Transmission Region on transmission storm channel 22 without reprogramming. This will permit vehicles maximum flexibility to assist in adjacent dispatching areas generally with no reprogramming required. However, when vehicles are transported beyond the adjacent dispatching area (and out of range of approximately 8 storm channels), the radios must be re-programmed by telecommunications personnel at the receiving location.

The TFS is responsible for requesting Telecommunications to reprogram vehicles that will be traveling beyond their 800 MHz range. The TFOps is responsible to have the incoming vehicles go to a staging location where Telecommunications personnel will provide the required reprogramming.

Section VIII
System Restoration

Black Start

Introduction:

The NERC EOP 005-2 and EOP 006-2 standards requires the AEP East and AEP West restoration plans to be approved by the respective PJM/SPP Reliability Coordinators. Copies of the Reliability Coordinator approved plans are stored on AEP TOps Sharepoint server for the AEP East and AEP West areas. Since there is an approved plan for each area, we need to refer to approved plan for additional information.

External entities previously identified have received a copy of the approved plan(s).

Section IX

Introduction DOE and NERC Event Reporting requirements

This section relates to the NERC reporting requirements under NERC standard EOP-004-2. AEP applicable NERC entities include Transmission Operators and Generator Operators registrations. In addition, the Department of Energy (DOE) requires OE-417 form, "Electronic Incident and Disturbance Report" be completed and filed for incidents listed in "Schedule 1" of form OE-417 and in the instructions for form OE-417.

AEP Event Reporting

Operating Plan

Version 5.0

Quarterly	Semi-annual	**Annual X**	As Needed

Revision History

Date	Revision Number	Description/Section Changed	Requested by:	Editor(s)
12-27-13	1.00	Original Issue – This document replaces CIP-001 "Sabotage Reporting"		Dennis Sauriol
2-21-14	1.01	Updated Attachment 1 and added attachment 3		Dennis Sauriol
12-15-14	2.0	Annual review, verified contact information		Dennis Sauriol
12-18-15	3.0	Annual review, verified contact info and added GOP reporting responsibility		Dennis Sauriol
12-9-16	4.0	Annual review, verified contact info and update attach 1		Dennis Sauriol
03-23-17	4.1	Updated with new EOP-004-3 with revision to Attachment 1 removal of SPS reference		Dennis Sauriol
12-12-17	5.0	Annual review, verified contact information. Added multiple signers for final approval, and list of Reg and Un-reg plants for reference	ENC	Dennis Sauriol

Review History

Submittal Date	Version	Implementation Date	Reviewer(s)
12-27-13	1.00	01-01-14	Dennis Sauriol, Dennis Kunkel, Ed Schnell, Stanley Partlow
12-15-14	2.0	01-01-15	Dennis Sauriol, Dennis Kunkel, Ed Schnell, Stanley Partlow
12-18-15	3.0	01-01-16	Dennis Sauriol, Dennis Kunkel, Ed Schnell, Stanley Partlow, William Thompson, Kary Bigbie, Fred Colburn, Frank Dinsmore, Robert Brown, Kevin Patton
12-9-16	4.0	01-01-17	Dennis Sauriol, Dennis Kunkel, David Ball, Stanley Partlow, William Thompson, Kary Bigbie, Fred Colburn, Frank Dinsmore, Robert Brown, Kevin Patten
03-23-17	4.1	04-01-17	Dennis Sauriol, Dennis Kunkel, David Ball, Stanley Partlow, William Thompson, Kary Bigbie, Fred Colburn, Frank Dinsmore, Robert Brown, Kevin Patten
11-01-17	5.0	01-01-18	Chris Shaffer, Dennis Kunkel, Kary Bigbie, Fred Colburn, Robert Brown, Todd Johnston, Leanna Lamatrice, Tim Bethel, Dave Daniels

Version Approval

ACTION	Version	NAME(S)	TITLE	SIGNATURE & DATE
Implementation	1.0	Paul B. Johnson	Managing Director-Transmission Operations, TOPS	12/27/13
Implementation	2.0	Paul B. Johnson	Managing Director-Transmission Operations, TOPS	12/8/14
Implementation	3.0	Paul B. Johnson	Managing Director-Transmission Operations, TOPS	12/22/15
Implementation	4.0	Paul B. Johnson	Managing Director-Transmission Operations, TOPS	12/30/16
Implementation	5.0	David Ball	Managing Director-Transmission Operations, TOPS	David R Ball 12/28/17
	5.0	Sam Queeno	Dir Physical Security	12/20/17
	5.0	Stephen Swick	Dir Cyber Intel & Defense	
	5.0	William Thompson	Dir Real Time Mkt Operations	William R. Thompson
	5.0	David McCammon	Dir Plant Engineering and Compliance Programs	12/18/2017
	5.0	Kevin Brady	VP - Market Operations	
	5.0	Dave Erickson	Dir Comm Ops Support	David G Erickson 12/13/17

Background:

Disturbances, destruction or unusual occurrences that jeopardize the Reliability of the Bulk Electric System, or result in system equipment damage or customer interruptions need to be reported to the appropriate entities. Therefore, NERC Standard EOP-004-3 requires the reporting of certain events. This Operating Plan summarizes those requirements and sets forth AEP's program to address the requirements. Refer to NERC Standard EOP-004-3 for the complete requirements. DOE form OE-417 covers additional reporting requirements such as cyber events and loss of customers.

References:

NERC Reliability Standard EOP-004-3
AEP Physical Security Investigation and Reporting Policies and Procedures AEP Cybersecurity Incident Response & Reporting

Process:

Recognition:

It is critical that AEP employees focus on reporting all types of events and activities, suspicious or otherwise that could jeopardize the reliability of the Bulk Electric System. For example, what appears as vandalism in a substation yard or control house may be exactly what it seems, or it might be part of a larger act. See Attachment 1 for a list of all events that need to be reported. Attachment 2 of this document illustrates the reporting process.

Reporting Responsibilities:
AEP Security (Physical and Cyber)

- AEP employees should focus on reporting all types of suspicious activity to AEP Physical Security
  - 1-866-747-5845 or Audinet 8-200-1337.
  - AEP Physical Security will ask if the incident has been reported to local law enforcement. If not, AEP Physical Security will request the caller to contact and report to local law enforcement if applicable.
- When AEP employees report information concerning suspicious activities, the AEP Cyber Security team will evaluate cyber security incidents in accordance with the AEP Cybersecurity Incident Response & Reporting document and the AEP Physical Security team will evaluate physical security incidents in accordance with the AEP Physical Security Investigation and Reporting Policies and Procedures.
- AEP Physical Security and/or AEP Cyber Security will work with the appropriate business unit(s) and with law enforcement or investigative authorities to investigate the incident and report the findings of that investigation to the appropriate business unit(s) for report filing per Attachment 1.
- If applicable, AEP Security will submit the report to the NERC Electricity Information Sharing and Analysis Center (NERC EISAC). AEP participates with the NERC EISAC and reports and receives alerts pertaining to incidents of a physical or electronic (cyber) nature.

Transmission Events

The Transmission System Control Center Reliability Coordinator or Corpus Christi TDC Dispatcher are responsible for completing and filing all reports within applicable time requirements for AEP Transmission Facilities as seen in Attachment 1 with NERC and other entities documented in this plan (see below) with a copy being sent to the following recipients.

1. Transmission Operations (TOPS) management.
2. Transmission NERC Compliance (TRELCOMP) email group; trelcomp@aep.com
3. Enterprise NERC Compliance (ENC) email group; enc@aep.com
4. Transmission to notify the On-Call Engineer and provide an electronic copy to TOPS Management

The On-Call Engineer, System Control Center (SCC) or Corpus Christi TDC management can be consulted for assistance in completing the report.

Generation Events

Real-Time Market Operations is responsible for completing and filing all reports within applicable time requirements for AEP Generation Facilities as seen in Attachment 1 with NERC and other entities documented in this memo (see below) with a copy being sent to the following recipients.

1. Generation Management
2. Generation NERC Compliance (GenNERC) email group; gennerc@aep.com
3. Enterprise NERC Compliance (ENC) email group; enc@aep.com
4. **Commercial Operations Compliance email group; cop_compliance@aep.com**

Generally copper theft incidents will not be reported under this policy. However, copper theft incidents that result in customer outages or include control house breaches or other unusual circumstances will be reviewed by Transmission and Security personnel to determine if reporting is appropriate.

Where to File

All reports sent electronically shall be in the PDF format and for external parties a read-receipt will be requested.

Reports shall be filed within the required time period as shown in attachment 1 to the following entities:

1. To NERC:
    a. Electronically, via an attachment to e-mail sent to: **systemawareness@nerc.net**
    b. Or faxed to: 404-446-9770 or phone: 404-446-9780
2. To the DOE (if required)
    a. Electronically, via an attachment to e-mail sent to: **doehqeoc@hq.doe.gov**
    b. Or faxed to: 202-586-8485 or phone: 202-586-8100
3. To the appropriate Regional Entity (RE)
    a. Reliability First: **disturbance@rfirst.org**
    b. SPP: **sppevents@spp.org**

c. TRE: **rapa@texasre.org**

4. To the relevant NERC Reliability Coordinator
   - **a.** PJM: e-mail: **dispsup@pjm.com**, FAX: 610-666-4287
   - **b.** SPP: e-mail: **security@spp.org**, FAX: 501-803-3956
   - **c.** ERCOT: e-mail: **shiftsupv@ercot.com;**

If the event is applicable to both EOP-004-3 and DOE OE-417, responsible parties within AEP will file a DOE OE-417 Report on the incident since the reporting time requirement is shorter than EOP-004 Attachment 2. The DOE Form OE-417 can be submitted to NERC in place of the EOP-004-3 Attachment 2 so there is no need to file both reports. Once an event has been recognized to meet the threshold, the form must be submitted within the applicable time frame as shown in Attachment 1. See Attachment 3 on instructions for filling out and filing OE-417.

Attachment 1

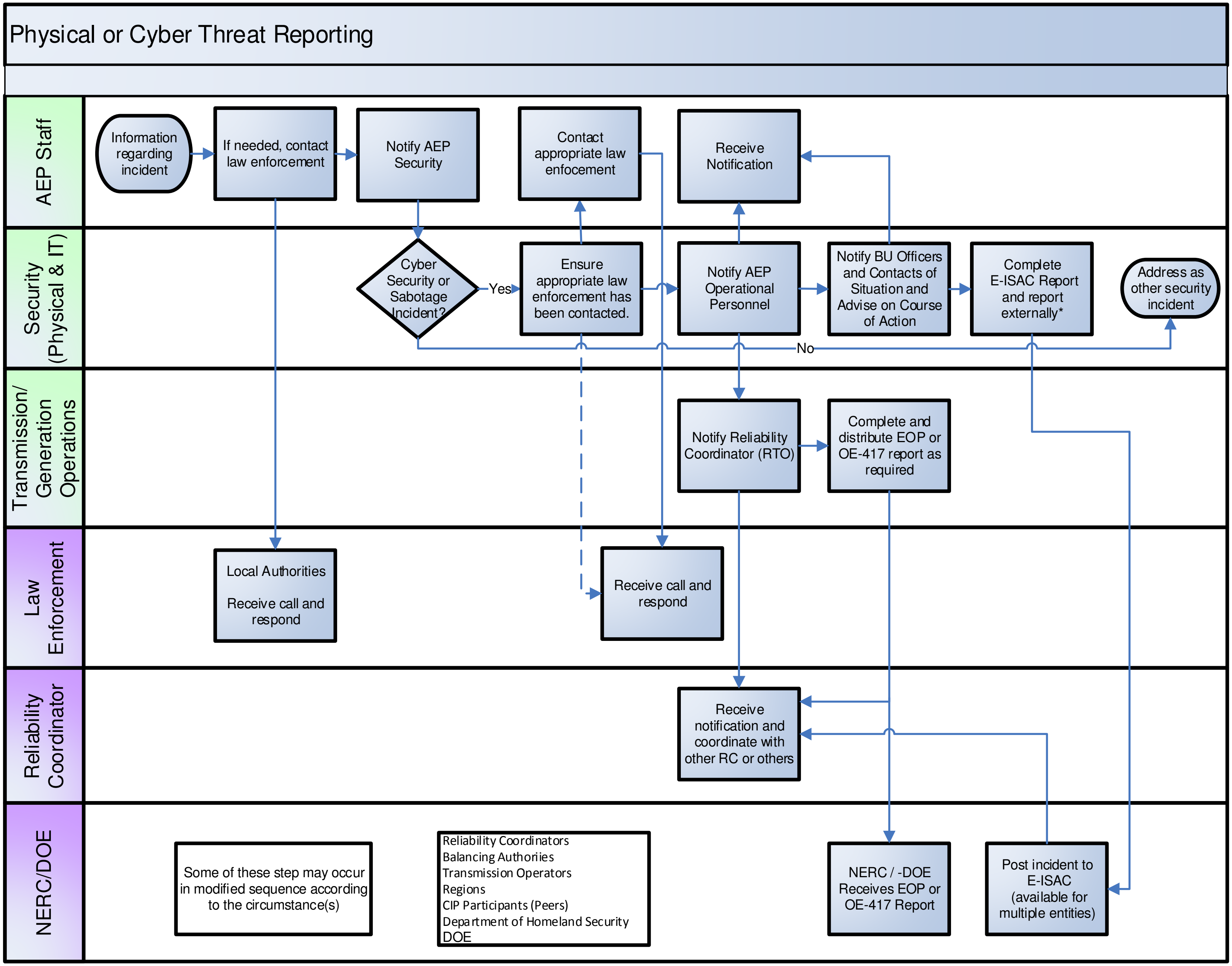
Incident	Threshold	EOP-004 Attach 2 and/or OE-417 Reportable	File Report within:	Who Files Report for AEP Texas?	Who Files Report for AEP West?	Who Files Report for AEP East?	File Report with
Damage or destruction of a facility	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West & SPP	SCC East & PJM	NERC, RC, RE
Damage or destruction of a Facility **	Damage or destruction of its Facility that results from actual or suspected intentional human action.	EOP-004 Attach 2	24hrs	CC TDC or Gen Disp.	SCC West or Gen Disp.	SCC East or Gen Disp.	NERC, RC, RE
Physical threats to a Facility **	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	EOP-004 Attach 2	24hrs	CC TDC or Gen Disp.	SCC West or Gen Disp.	SCC East or Gen Disp.	NERC, RC, RE
Physical threats to a BES control center	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE
BES Emergency requiring public appeal for load reduction	Public appeal for load reduction event.	EOP-004 Attach 2 or OE-417	1 hr	ERCOT or CC TDC*	SPP or SCC West*	PJM or SCC East*	NERC, RC, RE, DOE
BES Emergency requiring system-wide voltage reduction	System wide voltage reduction of 3% or more.	EOP-004 Attach 2 or OE-417	1 hr	ERCOT	SPP or SCC West*	PJM or SCC East*	NERC, RC, RE, DOE
BES Emergency requiring manual firm load shedding	Manual firm load shedding ≥ 100 MW.	EOP-004 Attach 2 or OE-417	1 hr	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
BES Emergency resulting in automatic firm load shedding	Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE

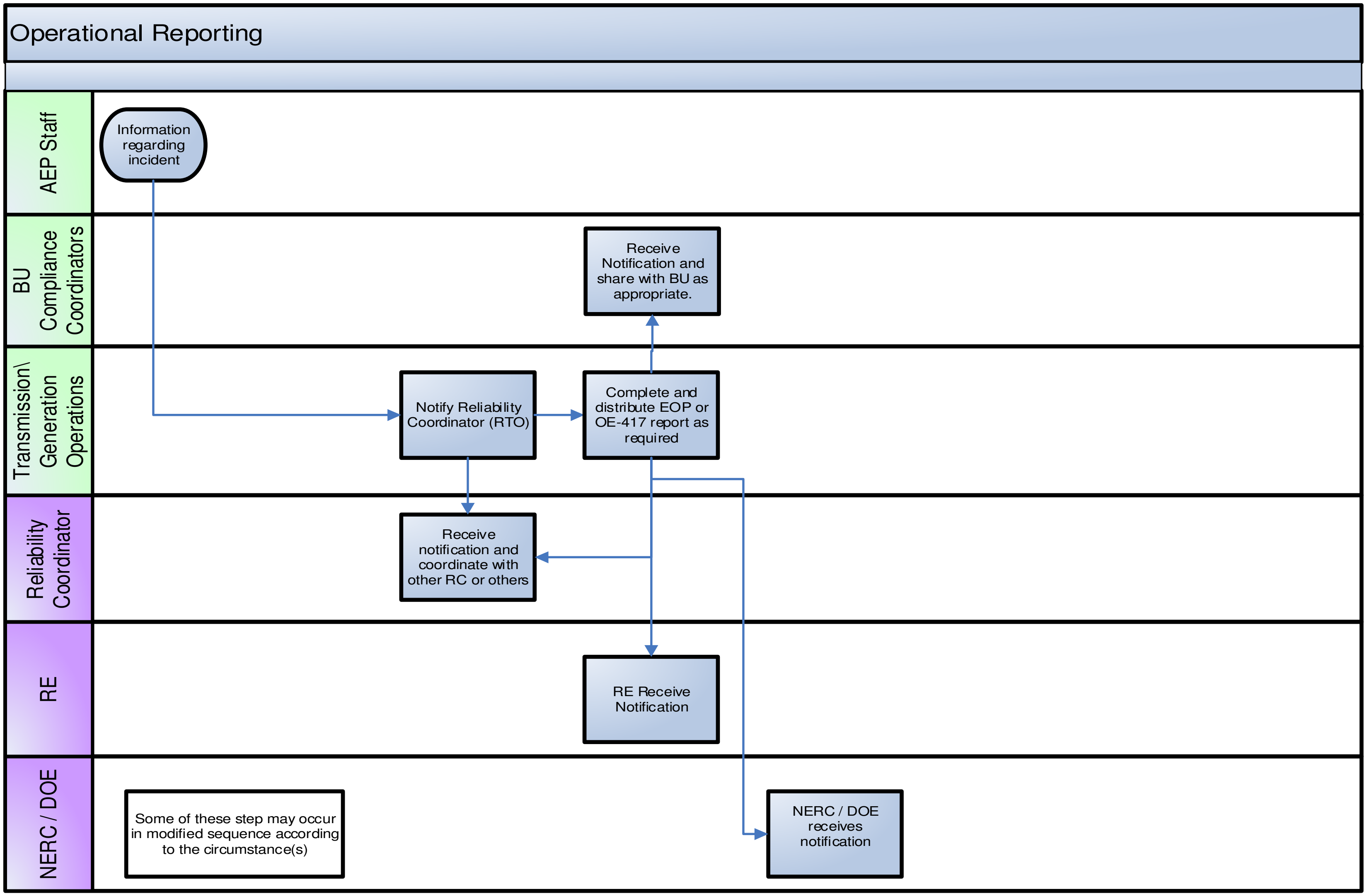
Voltage deviation on a Facility	Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE
IROL Violation (all Interconnections)	Operate outside the IROL for time greater than IROL Tv (all Interconnections)	EOP-004 Attach 2	24hrs	ERCOT	SPP	PJM	NERC, RC, RE
Loss of firm load	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand ≥ 3,000 OR ≥ 200 MW for all other entities	EOP-004 Attach 2 or OE-417	1 hr	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
System separation (islanding)	Each separation resulting in an island ≥ 100 MW	EOP-004 Attach 2 or OE-417	1 hr	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
Generation loss **	Total generation loss, within one minute, of : ≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	EOP-004 Attach 2	24hrs	N/A	Gen Disp.	Gen Disp.	NERC, RC, RE
Complete loss of off-site power to a nuclear generating plant (grid supply)	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement	EOP-004 Attach 2	24hrs	Corpus Christi TDC	N/A	SCC East	NERC, RC, RE
Transmission loss	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE
Unplanned BES control center evacuation	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE
Complete loss of voice communication Capability	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE
Complete loss of monitoring capability	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	EOP-004 Attach 2	24hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE
Physical attack	Causes major Interruptions or impact to critical infrastructure facilities or to operations	OE-417	1 Hr	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
Cyber Event[#]	Causes interruptions of electrical system operations	OE-417	1 Hr	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE

Complete operational failure or shut down of the transmission and/or distribution electrical system		OE-417	1 Hr	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
Physical attack	Could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems	OE-417	6 Hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
Cyber Event[#]	Could potentially Impact electric power system adequacy or vulnerability	OE-417	6 Hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
Loss of electric Service	≥50,000 customers ≥1 hour	OE-417	6 Hrs	Corpus Christi TDC	SCC West	SCC East	NERC, RC, RE, DOE
Fuel supply emergencies[#]	Could impact electric power system adequacy or reliability	OE-417	6 Hrs	Corpus Christi TDC	SCC West	SCC East & PJM	NERC, RC, RE, DOE

***-Initiating Entity is responsible for reporting**
**** All Incidents pertaining to: Cardinal, Conesville, Desert Sky,Trent Mesa, Racine, and R.P. Mone must be reported by Un-Reg Gen Dispatch. All other plant related incidents should be reported by Reg Gen Dispatch.**
 # Depending on the nature of the event, coordination among business unit(s) may be required to ensure accurate and timely reporting.

Attachment 2




Operational Reporting
AEP Staff
BU Compliance Coordinators
Transmission\ Generation Operations
Reliability Coordinator
RE
NERC / DOE
Information regarding incident
Receive Notification and share with BU as appropriate.
Notify Reliability Coordinator (RTO)
Complete and distribute EOP or OE-417 report as required
Receive notification and coordinate with other RC or others
RE Receive Notification
Some of these step may occur in modified sequence according to the circumstance(s)
NERC / DOE receives notification

Attachment 3

Overview: DOE OE-417 Reporting

The Department of Energy (DOE) requires OE-417 form, "Electric Emergency Incident and Disturbance Report" be completed and filed for incidents listed in "Schedule 1" of form OE-417 and in the instructions for form OE-417.

The Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form OE-417 to meet its overall national security and Federal Emergency Management Agency's National Response Framework responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. The data also may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems. (From US DOE Form OE-417 Instructions document)

References:

DOE Filing Site http://www.oe.netl.doe.gov/oe417.aspx
DOE Filing Instructions https://www.oe.netl.doe.gov/docs/OE417_submission_instructions.pdf
NERC Reliability Standard EOP-004-3

Procedures:

Reporting Responsibilities

The AEP Corpus Christi TDC, SCC East or SCC West Reliability Coordinator has the responsibility for filing Form OE-417 with the DOE and other applicable entities as shown in attachment 1 in the column "File Report With". The report will be filed with the appropriate entities as shown the in the "Where to File" section of this document.

DOE Report Form OE-417

DOE now utilizes an on line submittal process. Detailed line-by-line instructions for completing the form are available on the TOPS Sharepoint site or one line at http://www.oe.netl.doe.gov/oe417.aspx.

How to file the form

1. Access the site at https://www.oe.netl.doe.gov/OE417/ to fill out the form. Use the supplied password to log into the site.
2. Select "Enter New OE-417" if filing a new report. Proceed to fill out Schedule 1 and Schedule 2 of the form.
3. All applicable entities (DOE, NERC, RC, RE, etc.) have already been identified to receive a copy of the report once submitted. You can view the list of recipients under the "Recipients"

tab on the site. Important to note that if you "check" the box next to an entities name you will remove that entity from receiving a copy of the report.

4. If no form was filed over the weekend, that is, non-business days, capture the AEP Texas outage statistics in a PDF for the gap so that it can be made available to DOE, ERCOT, or TRE, upon request.
5. No interim updates are required if the loss of electric service is less than 50,000 customers.
6. File a final form when the loss of electric service is less than 50,000 customers to close the incident.

The Form OE-417 must be submitted to the DOE Operations Center within **one hour** if one of the following conditions applies:

1. Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations
2. Cyber event that causes interruptions of electrical system operations
3. Complete operational failure or shut-down of the transmission and/or distribution electrical system
4. Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system
5. Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident
6. Load shedding of 100 MW or more implemented under emergency operational policy
7. System-wide voltage reductions of 3 percent or more
8. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system

The Form OE-417 must be submitted to the DOE Operations Center within **six hours** if one of the following applies and none of the eight categories above apply

9. Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security system.
10. Cyber event that could impact electric power system adequacy or reliability.
11. Loss of electric service to more than 50,000 customers for 1 hour or more
12. Fuel supply emergencies that could impact electric power system adequacy or reliability

Update Reports: Schedule 1 and lines 13-17 in Schedule 2 should be re-submitted if significant information (or changes) regarding a reported incident or disturbance becomes available after the initial Emergency Alert or Normal Alert Report was submitted. Add the new information and/or changes to the original submission and resubmit the form, checking Update as the Alert Status on line 1 of Form OE-417. If no significant changes occur, the updated report should be filed at a minimum of every twelve (12) hours or at least once a shift.

Final Report: Within 72 hours of the incident a Final Report must be filed. An updated Form OE-417 Schedule 1 and all of Schedule 2 are both due within 72 hours of the incident to provide complete disruption information. Complete and revise Schedule 1 as necessary and check "Final" as Alert Status on line 1. The 72 hour timer begins when the event is substantially resolved. In the case of customer outages, the event would end when the

number of customers outaged is below 50,000 for more than one hour and that number is not predicted to rise. Real Time Operations is responsible for filing the final report.

Distribution Events

For reporting guideline #11, the trigger will be when we reach 50,000 customers out for 1 hour or more in a single AEP Operating Company (APCO, I&M, etc). Customer outage totals should be gathered from the Outage Management System (OMS) and if necessary validated with the appropriate DDC manager or their designee.

Section X

Emergency Communications

The following items from PJM and SPP define the conditions when emergency communications should take place between Reliability Coordinators, System Control Center Operators or Operating Authorities, and Transmission Dispatchers.

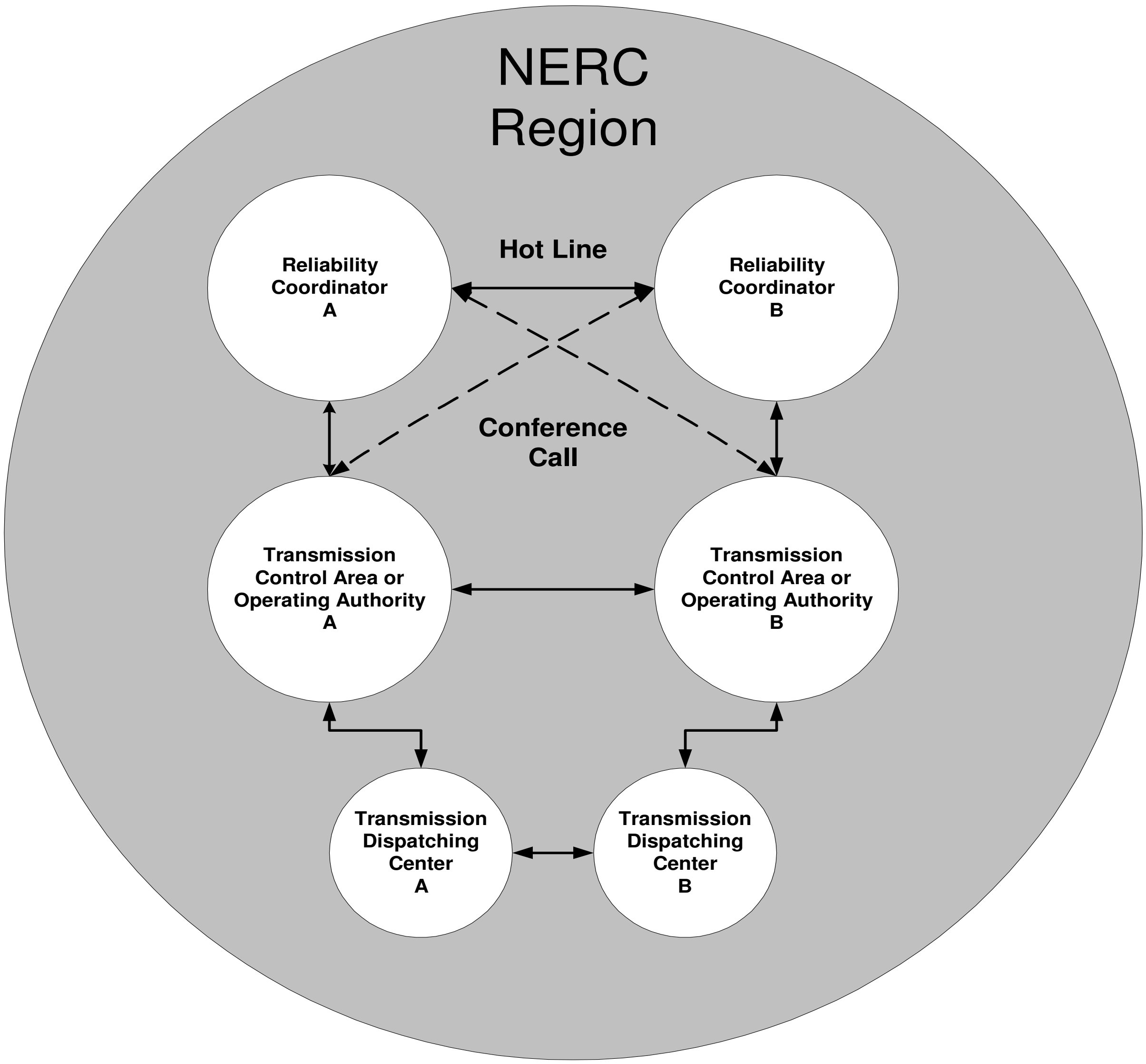
PJM Manual 01 Section 2.6.1 addresses emergency EMS outages. Section 3.2.3 addresses data exchange during a loss of EMS data.

SPP Operating Criteria section 8 addresses emergency communications in the SPP area.

NERC standard COM-001-3 has communication capability requirements as noted below.

> Each Transmission Operator shall have Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority, Distribution Provider, Generator Operator within it Transmission Operator Area and adjacent Transmission Operator.
>
> Each Transmission Operator shall notify entities within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer.

The following communications diagram depicts the various paths of the required communication:



The Hot Line is typically between Reliability Coordinator and Reliability Coordinator. The Conference Call is usually requested by a Reliability Coordinator or Transmission Control Area or Operating Authority, and will involve several Reliability Coordinators, Transmission Control Area's and Operating Authorities.

The AEP communication system has been designed to allow control and operation of the geographically dispersed stations and plants from the System Control Center (SCC), and 5 Transmission Dispatch Centers (TDC). This system has been designed to maintain reliable communication paths for the exclusive use of the SCC, TDC's and station personnel during emergencies. AEP East and AEP West utilize public switched communication networks for external communications. Internal communications is via company owned or leased facilities including microwave and fiber optic media.

Types of Communication Systems

800 Mhz Radio and Fiber Optics System

The backbone of the communication system is the AEP 800 Mhz radio and fiber optics system, its equipment and path switching techniques.

The availability of 800 Mhz and fiber optics facilities during emergency situations is ensured by each microwave terminal and repeater station having an emergency power supply using a propane-powered automatic generator with sufficient fuel for three to fourteen days (typically 7 days), or 24-hour emergency batteries.

Audinet System

The AEP Audinet system permits override on any congested tie-line group, disconnecting lower priority users. To minimize the possibility of overheating temperature-sensitive switches, air conditioning for the communication equipment rooms is supplied from the emergency generators during a power outage.

TDC to Plant Communication

Plant control rooms have a telephone console with a button dedicated to the Transmission Dispatching Centers (TDC) communication. At the TDC’s, each of the telephone consoles has a button dedicated to each plant. All of the above equipment is battery-powered and will continue to function if plant power is lost.

Satellite Communications

Satellite communication systems are also available in case of a loss of both the dedicated and the public telephone systems. Satellite Communications are the preferred backup systems for PJM, ERCOT, and the SPP Reliability Coordinators, as well as, Market Operations.

Scada Communications – AEP East/PJM

The Eastern AEP SCADA host computers communicate with the substation RTUs via a communication front-end called the Station Data Gateway (SDG). The SDG can be located either local to the SCADA host or remote. There are currently more SDGs than SCADA hosts to provide for sufficient diversity in case of the loss of a SDG.

The SDGs communicate with the SCADA host via the internal Transmission SCADA Network (TSN) via TCP/IP. The TSN provides redundant paths to each SDG to provide for a single contingency communications path loss. Between the redundant communication paths and diverse SDG locations, AEP has constructed an extremely robust network for RTU communications.

Scada Communications – AEP West/SPP

The Western AEP SCADA host computers communicate with the substation RTUs via a communication front-end called the Station Management Platform (SMP) computers. The SMPs can be located either local to the SCADA host or remote. They are currently co-located with the SCADA hosts, but there is a project underway to expand the number of SMPs to provide for sufficient diversity in case of the loss of the single SMP that currently communicates with all RTUs for the Operating Company.

The SMPs communicate with the SCADA host via the internal Transmission SCADA Network (TSN) via TCP/IP. The TSN provides redundant paths to each site to provide for a single contingency communications path loss. Between the redundant communication paths and diverse SMP locations, AEP has constructed an extremely robust network for RTU communications.

AEP Satellite Telephones

[redacted]

<u>800 Mhz Talk Groups</u>

AEP/PJM		
***NO CONDUIT RULE APPLIES!!		
Plant	**Unit**	**Talk Group**
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

AEP/SPP		
***NO CONDUIT RULE APPLIES!!		
Plant / TDC	**Unit**	**Talk Group**
AEP/SPP - PSO		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
AEP/SPP - SWEPCO		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Decision Making/Collaboration

It is important to be aware and to determine when the transmission system is in a stressed or abnormal state. Reliability Coordinators, System Control Center Operators and Transmission Dispatchers have the authority to implement emergency procedures to remedy emergency or abnormal conditions. In this regard, emergency and/or abnormal conditions should be reported, and discussed with the System Control Center Operators, Reliability Coordinators, and local Engineering support staff as necessary, to help determine the nature and severity of the emergency or abnormal system and to further determine and agree on actions to be taken. Urgency of a situation must be clearly communicated to assure timely decisions on actions to relieve the emergency or abnormal condition and to return the system to a normal or secure state. If it is determined that an emergency state, or near emergency state exists; then the necessary emergency communication contacts should be made by the system experiencing the abnormal conditions. The notifications should be made to those systems most affected by the abnormal conditions (see communications diagram), and the Reliability Coordinator can make use of the Reliability Coordinator Information System (RCIS), and NERC Hot Line, to inform other Reliability Coordinators of the situation.

In some instances a Hot Line may be set up between Reliability Coordinators, or a Conference Call may be initiated between the Reliability Coordinators and Transmission Control Area's or Operating Authorities affected by the abnormal system to discuss the nature of the emergency, what corrective actions are being taken to return the system to a normal state, and how long the system will be in the abnormal state.

Communication Failures

When problems are encountered with either the IT systems or Telecom infrastructure, the System Control Center Operators /Dispatchers are trained to contact the on-call support personnel, and/or the Network Operations Center (NOC) and/or the SCC IT support group. Once that call is made, the NOC and SCC IT support group are charged with troubleshooting the issue, making appropriate support call-outs as required if they are not able to correct the problem, and with keeping all concerned parties apprised of the conditions as appropriate. The NOC monitors AEP's internal communications system functions 24/7 and advises the SCC and TDC's of any planned or emergency outages that could affect our telecommunications or SCADA facilities via e-mail.

In the case of the loss of a critical Transmission RTU, the Transmission Dispatcher may request that field personnel physically man the station. The decision to man the station needs to be coordinated with the SCC. The SCC will notify the Reliability Coordinator (PJM or SPP) of the loss. The SCC, the Oncall Engineer and the Reliability Coordinator will evaluate the impact of the RTU loss to their respective EMS systems.

Refer to the SCC "Real-Time Data Integrity Procedure" document on the TOps ShareNow site for additional information on the detailed corrective actions the SCC follows.

Testing

- Satellite communications are routinely tested with SPP, PJM, Market Operations, PSO and SWEPCO.
- Emergency telephone communications contact numbers with interconnected utilities listed in Appendix VII are updated as part of the EOP .
- 800 Mhz communications will be tested though normal usage or by a designated test.

Refer to the most recent copy of the following Operating Memo on the SCC – All Inclusive>Communications>Satellite Phones>TOPS ShareNow folder(s) for more details:

- TOR Satellite Phone Testing

Section XI

The NERC Standards EOP-005 and PER-005 describe general training requirements for this plan. It is the responsibility of the various AEP Training departments to develop and maintain an emergency operating training program for each area of responsibility.

System Operator Training

Purpose – Implement System Operator training to ensure plans, procedures, and resources are practiced/simulated to restore the electric system to a normal condition in the event of a partial or total shut down of the system.

Objectives – Learning objectives shall be based on this Emergency Operating Plan and/or company-specific reliability-related tasks performed by System Operators.

Requirements

- System Operators shall receive emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel.
- System Operators shall be trained in the implementation of the AEP System restoration plan. Such training shall include simulated exercises, if practicable.
- Emergency Operations drills or simulations will be conducted each year to evaluate the effectiveness of the plan, and to evaluate the knowledge of the SCC Reliability Coordinators and Transmission Dispatchers.
- Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

Appendix I

Station Equipment Problems Resulting from Loss of AC

Station Batteries

Station batteries may have only six (6) hours of useful life in very cold weather. MOAB's should be operated manually (provided the line is de-energized) to conserve battery life.

Portable Generators

The Transmission Regions have portable generators capable of providing emergency power to battery chargers at blacked-out stations.

Operation of Transmission Breakers During a Loss of Auxiliary Power

All transmission circuit breakers on the AEP system use a form of stored energy to operate the breaker mechanism. This stored energy is in the form of compressed air or gas, compressed springs, or station batteries. Unless this stored energy has been lost due to leakage or discharge, each breaker should be capable of a minimum of one open-close-open sequence of operations without the need for AC auxiliary power.

Closed oil circuit breakers are always capable of being tripped. The energy used to close the breaker also charges the tripping springs. The BBC/ITE type GA-145, GA-362 and Westinghouse type SF-362 and SFA-800 breakers also use spring energy to trip and can always trip when closed; however, proper interruption depends upon having the proper SF6 gas pressures. All other transmission breakers rely on compressed air or gas to provide the energy to trip the breaker. Those with hydraulic mechanisms use oil or SF6 gas for current interruption and have hydraulic systems small enough to be charged by a manual operator on the pump. Pneumatically operated breakers, which use oil or SF6 gas for current interruption, use compressed air at pressures and volumes that can be supplied from a cylinder of compressed dry air or nitrogen.

Air blast breakers use compressed air to operate the breaker and for current interruption. The amount of air required per operation would make supplying the air from gas cylinders impractical, but not impossible. Mechanisms using spring closing can perform only one closing operation without recharging. All other types of mechanisms can provide between four and eleven stored operations, depending upon the type of breaker. With normal leakage most breakers will be capable of close-open operation for several days after the loss of auxiliary power. However, the loss of heaters in cold weather may cause difficulties in the operation of some breakers. This is especially true for two-pressure SF6 breakers in which the high pressure gas must be kept above 52 degrees Fahrenheit to keep the pressure above the MTP point. The following information may be used to determine the capabilities for operation of the various types of circuit breakers following a loss of AC power.

Breaker Details

Oil Circuit Breakers - All Types

Tripping
All can be tripped from the closed position.

Closing

Pneumatic mechanisms	A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure to the operating range.
Hydraulic mechanisms	A hand operator on the pump can be used to raise the pressure to the operating range.
Spring mechanism	A ratchet handle and socket can be used to charge the closing springs.
Motor or solenoid mechanism	A station battery or substitute DC power supply is required.

Air Blast Breakers - General Electric Type ATB, Delle Type PK and Brown Boveri Type DLF

Operating air is supplied from a high pressure reservoir that is filled by an electrically driven air compressor.

Tripping and Closing
Proper air pressure in the low pressure system is required for any operation. The high pressure system can be connected to the high pressure supply of another breaker, or cylinders of dry air or nitrogen may be used to raise the low pressure system pressure. One cylinder would supply approximately one close-open operation of a 138-kV breaker.

Two-Pressure SF6 Breakers - BBC/ITE Type GA, Westinghouse Types SF, SFA, and SFV

Compressors and heaters are required to maintain the high pressure gas temperature above 52 degrees Fahrenheit and the pressure above 230 psi. Consequently, at ambient temperatures below 52 degrees Fahrenheit these breakers will become inoperable within hours of a loss of AC power and will remain so until the restoration of AC power. If the circuit breaker has proper SF6 gas pressures, operation will depend upon the mechanism.

Tripping

- Westinghouse type SF and SFA, and ITE/Brown Boveri type GA circuit breakers can be tripped from the closed position. The tripping springs are charged when the breaker is closed.
- The Westinghouse type SFV uses high pressure SF6 gas to operate the mechanism and move the contacts and can be operated if the SF6 gas pressure is above the MTP point.

Closing

- The SF, SFA and GA breakers have pneumatic closing mechanisms. A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure to the operating range.
- The SFV uses the high pressure SF6 gas to operate the mechanism and close the contacts. It can be closed if the SF6 gas pressure is above the low pressure cut-off point.

<u>Single Pressure SF6 Breakers -</u>
<u>BBC Types PA, ELF and ELK, Delle Types FR and FX, Siemens Type 3AT5 and Hitachi</u>

These breakers use SF6 gas and 86 psig and do not require either gas compressors or heaters. If the SF6 pressure is above the cut-off point, operation will depend upon the mechanism.

Tripping

- Delle type FR, FX; BBC type PA, ELK; and Siemens type 3AT5 use hydraulic mechanisms. A hand operator on the pump can be used to raise the pressure to the operating range.
- Brown Boveri type ELF, the Hitachi type OFPTB, and the Westinghouse type SP use pneumatic mechanisms. A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure to the operating range.

Closing

- The FR, FX, ELK and 3AT5 use hydraulic mechanisms and can be pumped up with a hand operator.
- The Westinghouse SP and Hitachi OFPTB close from springs charged by the tripping operation.
- The ELF uses a pneumatic mechanism to close the breaker. A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure.

Many types of breakers can be operated manually, but the breaker must be de-energized with disconnects open before this is done. Local Station Department breaker personnel or breaker specialists should be contacted to supervise manual operation.

The approximate AC power requirements for compressors and heaters for transmission breakers are listed below.

Oil Circuit Breakers		
345-kV	10 kW	
138-kV	<5 kW	
Air Blast Breakers - All 240 Volt 3-Phase		
765-kV	Delle type PK BBC DLFK Definite Purpose Breaker	20 kW 20 kW 20 kW
345-kV	GE Type ATB Delle type PK BBC type DLFK	20 kW 15 kW 15 kW
138-kV	GE type ATB Delle type PK	15 kW 15 kW
Two Pressure SF6 Breakers - All 240 Volt 3-Phase		
765-kV	Westinghouse SFA	25 kW
345-kV	ITE/BBC GA	15 kW
138-kV	Westinghouse type SFV ITE/BBC type GA	25 kW 10 kW
Single Pressure SF6 Breakers - All 240 Volt 3-Phase		
765-kV	BBC type ELF Siemens 3AT5 Delle FR	7.5 kW 5 kW 30 kW
All Other Single Pressure SF6 Breakers < 5 kW		

Table AII-1
AC Power Requirements for Compressors and Heaters for Transmission Breakers

Restoration of AC Power to Air Blast and SF6

Breakers Following an Interruption in Cold Weather

The proper operation of all of the 765-kV breakers on the AEP system, as well as many of the other system breakers, depends to a great extent on the maintenance of proper temperatures and pressures in the breaker. This in turn depends on the station service power to operate the heater and compressor motors. Failure to maintain these pressures and/or temperatures may result in damage to breaker components, mis-operation, or failure to operate. The following information is intended to provide guidelines to the system operators for situations where station service power has been lost during cold weather.

The Delle Type PK, Brown Boveri Type DLFK and General Electric Type ATB breakers use compressed air at 360-510 psi to operate the contacts and interrupt fault current. This operating air is supplied by 3600 psi storage air, which is replenished by compressors. Heaters in the compressor, relay and control cabinets provide heat to prevent condensation of moisture in the breaker cabinets and the breaker air systems. Condensation on the relays, controls or panel surfaces can result in corrosion, tracking and component failure. Condensation and freezing inside the air system can result in air leaks, blockages in air passages or jammed components, resulting in a loss of air or a failure to operate. Loss of heat in the compressor cabinet will allow the compressor oil to thicken, increasing the starting torque required of the motor.

It is very important that all the heaters and thermostats in these breakers be operating correctly. Should a breaker have experienced a loss of AC power to the heaters for more than 30 minutes in sub-freezing weather, it will be necessary to restore power to the heaters before closing the breaker or operating the compressor. To prevent the compressor from starting when power is restored, the 2-pole AC control power switch in the compressor control cabinet should be opened. The closing of an open air blast breaker should be delayed until the cabinet heaters have warmed up the valves. It is recommended that a minimum time of 30 minutes at 32 degrees Fahrenheit, increasing to 1 hour at 0 degrees Fahrenheit, be observed before operating the compressor or closing the breaker.

Two pressure SF6 breakers depend on heaters to prevent liquefaction of the high pressure (250 psi) SF6 gas at temperatures below 60 degrees Fahrenheit. Following the loss of power to the heaters, the SF6 gas in the high pressure system will begin to liquefy as its temperature drops until the saturation point is reached; at 0 degrees Fahrenheit it would be 100 psi.

On the ITE-Brown Boveri Type GA and Westinghouse Type SFA breakers, the compressor governor switch monitors the high pressure system and, if the pressure drops enough, will close to start the compressor when power is restored. The Westinghouse Type SFV breaker controls the compressor with a pressure switch on the low pressure system that will not respond to a pressure drop in the high pressure system unless the pressure in the low pressure system is raised by operations or gas leaks.

Immediate starting of a compressor under these conditions should be avoided for two reasons. First, the oil in the compressor may be cold, causing lubrication or starting problems that could damage the compressor or motor. Second, in the Type GA and SFA breakers, there will probably be sufficient SF6 in the high pressure system to achieve normal pressure once the normal temperature is reached.

Operating the gas compressor before all the liquid SF6 is evaporated will add additional SF6 to the high pressure system, possibly lowering the low pressure system to the alarm or compressor lockout point and causing excessive pressure on the high pressure system when normal operating temperature is reached. Since the SF6 heaters are primarily intended only to maintain a satisfactory temperature, they may require hours to regain this temperature if the outage was long or the ambient temperature very low. Until enough liquid SF6 evaporates to bring the gas pressure above the MTP point, the breaker will be in a breaker failure mode. This time can be shortened by selective valve operation and compressor operation; however, this should only be done by a breaker specialist familiar with this type of breaker.

All system breakers are interlocked to prevent operation if the air or gas pressure is too low to successfully operate the breaker. In an urgent system operating condition, these procedures (which are recommended to reduce the possibility of compressor system damage or breaker mis-operation) may be disregarded in the interest of restoring or maintaining service.

Section II C-11 Loss of Station Auxiliary Power of the AEP EHV System Operating Guidelines manual contains additional information on the operation of circuit breakers during an outage. A copy of the manual is kept on the TOPS ShareNow site at **>Engineering >AEP EHV System Operation Guide > EHV OPERATING GUIDELINE**

TOPS Process for Loss of Station DC is on the TOP ShareNow site at **>TDC> General Policies & Procedures> TOPs Loss of DC Process>TOPs Loss of DC Process**

Appendix II

High Voltage Limits on Equipment – AEP East/PJM System

1. High Voltage Limits at Transmission Stations – Anticipating Light Transformer Loadings

   See ***Table AII-1: High Voltage Limits During Off Peak Load Periods***

2. High Voltage Limits at Transmission Stations – Anticipating Heavy Transformer Loadings

   See ***Table AII-2 High Voltage Limits During Peak Load Periods***

3. Location and time delay setting of overvoltage relays (trip at 811-kV, 1.061 p.u.)

   See ***Table AII-3 Location and Time Delay Setting of Overvoltage Relays***

4. High Voltage Limits for Circuit Breakers

   See ***Table AII-4 High Voltage Limits for Circuit breakers***

Note: Data in tables taken from section V-C Station Voltage Limits of the AEP EHV Operating Guidelines.

Station		High Voltage Limit	Liability
Amos	765-kV	103.3%	T3 @ 108.75% of tap setting
Axton	765-kV	105.0%	Shunt reactors
Baker	765-kV	104.6%	765-kV breakers
Belmont	765-kV	104.6%	T-5 current transformer
Broadford	765-kV	104.6%	765-kV breakers
Cloverdale	765-kV	104.6%	765-kV breakers
Cook	765-kV	102.6%	T-2 @ 108% of tap setting
Culloden	765-kV	104.6%	765-kV breakers
Dumont	765-kV	104.6%	765-kV breakers
FlatLick	765-kV	104.6%	765-kV breakers
Gavin	765-kV	103.3%	T-1 & T2 @ 108.75% of tap setting
Greentown	765-kV	104.5%	T-1 and T-2 @ 110% of tap setting
Hanging Rock	765-kV	104.6%	765-kV breakers
Jacksons Ferry	765-kV	104.6%	765-kV breakers
Jefferson	765-kV	104.6%	765-kV breakers
Joshua Falls	765-kV	104.6%	765-kV breakers
Kammer	765-kV	102.2%	Mitchell T-1 @ 107.5% of tap setting
Marquis	765-kV	102.2%	T-1 and T-2 @ 107.5% of tap setting
Marysville	765-kV	104.6%	765-kV breakers
Mountaineer	765-kV	103.3%	T-1 @ 108.75% of tap setting
North Proctorville	765-kV	104.5%	T-1 @ 110% of tap setting
Maliszewski	765-kV	104.6%	765 kV breakers
Rockport	765-kV	104.6%	765-kV breakers
South Canton	765-kV	104.5%	T-3 @ 110% of tap setting
Sullivan	765-kV	102.5%	T-1 and T-2 @ 110% of tap setting
Wyoming	765-kV	104.6%	T-1 and T-2 current transformers
Belmont	500-kV	113.5%	T-5 @ 107.5% of tap setting
Broadford	500-kV	113.5%	T-4 @ 107.5% of tap setting
Cloverdale	500-kV	109.7%	T-6A and T-6B @ 107.5% of tap setting
Jacksons Ferry	500-kV	110.5%	T-1 @ 107.5% of tap setting
Kammer	500-kV	116.5%	T-200 @ 107.5% of tap setting
Nagel	500-kV	110.0%	500-kV breakers

Table AII-1
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
Allen	345-kV	104.9%	345-kV breakers
Amos	345-kV	104.9%	345-kV breakers
Baker	345-kV	104.8%	Big Sandy T-2 @ 107.5% of tap setting
Beatty	345-kV	104.9%	345-kV breakers
Benton Harbor	345-kV	111.0%	T-A and T-B @ 110% of tap setting
Beverly	345-kV	104.9%	345 kV breakers
Bixby	345-kV	104.9%	345-kV breakers
Breed	345-kV	106.8%	345-kV breakers
Canton Central	345-kV	104.9%	345-kV breakers
Clifty Creek	345-kV	103.5%	T-1 through T-6 @ 105.3% of tap setting
Cloverdale	345-kV	104.9%	T-10 @ 107.5% of tap setting
Conesville	345-kV	104.9%	T-4, T-5 and T-6 @ 107.5% of tap setting
Convoy (RP -Mone)	345	104.9%	345-kV breakers
Cook	345-kV	104.9%	345-kV breakers
Corridor	345-kV	104.9%	345-kV breakers
Darwin	345-kV	104.9%	345-kV breakers
Dequine	345-kV	104.9%	345-kV breakers
DeSoto	345-kV	104.9%	345-kV breakers
Dumont	345-kV	104.9%	345-kV breakers
East Elkhart	345-kV	111.0%	T-2 @ 110% of tap setting
East Lima	345-kV	104.9%	345-kV breakers
Eugene	345-kV	104.9%	345-kV breakers
Fall Creek	345-kV	104.9%	345-kV breakers
Foothills	345-kV	104.9%	345-kV breakers
Fostoria Central	345-kV	104.9%	345-kV breakers
Galion	345-kV	104.9%	345-kV breakers
Hayden	345-kV	104.9%	345-kV breakers
Hyatt	345-kV	104.9%	345-kV breakers
Jackson Road	345-kV	111.0%	T-3 @ 110% of tap setting
Kammer	345-kV	104.9%	345-kV breakers
Kanawha	345-kV	104.9%	345-kV breakers
Kenzie Creek	345-kV	111.0%	T-1 @ 110% of tap setting
Keystone	345-kV	104.9%	345-kV breakers
Kirk	345-kV	104.9%	345-kV breakers
Kyger Creek	345-kV	104.2%	T-1 through T-5 @ 106% of tap setting
Marquis	345-kV	104.9%	345-kV breakers
Marysville	345-kV	104.9%	345-kV breakers
Matt Funk	345-kV	104.9%	345-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
Muskingum	345-kV	104.9%	345-kV breakers
Ohio Central	345-kV	108.1%	T-1 @ 110% of tap setting
Olive	345-kV	104.9%	345-kV breakers
Reynolds	345-kV	109.0%	T-1 @ 110% of tap setting
Roberts	345-kV	111.0%	T-2 @ 110% of tap setting
Robison Park	345-kV	104.9%	345-kV breakers
Sorenson	345-kV	104.9%	345-kV breakers
South Canton	345-kV	104.9%	345-kV breakers
Southeast Canton	345-kV	108.1%	T-1 @ 110% of tap setting
Southwest Lima	345-kV	104.9%	345-kV breakers
Sporn	345-kV	104.9%	345-kV breakers
Tanners Creek	345-kV	104.9%	345-kV breakers
Tidd	345-kV	103.0%	CB fault duties
Tri State	345-kV	104.9%	345-kV breaker
Twin Branch	345-kV	104.9%	345-kV breaker
Waterford	345-kV	104.9%	345-kV breakers
West Bellaire	345-kV	108.1%	T-1 @ 110% of tap setting
West Millersport	345-kV	104.9%	345-kV breakers
Zelda	345-kV	104.9%	345-kV breakers
Greentown	230-kV	107.5%	T-2 @ 107.5% of tap setting
Nagel	230-kV	112.2%	T-5 @ 107.5% of tap setting
Allen	138-kV	105.1%	138-kV breakers
Amos	138-kV	105.1%	138-kV breakers
Axton	138-kV	105.1%	138-kV breakers
Beatty	138-kV	105.1%	138-kV breakers
Benton Harbor	138-kV	105.1%	138-kV breakers
Big Sandy	138-kV	105.1%	138-kV breakers
Bixby	138-kV	105.1%	138-kV breakers
Broadford	138-kV	105.1%	138-kV breakers
Canton Central	138-kV	105.1%	138-kV breakers
Claytor	138-kV	105.1%	138-kV breakers
Clinch River	138-kV	105.1%	138-kV breakers
Cloverdale	138-kV	105.1%	138-kV breakers
Conesville	138-kV	104.6%	T-2 and T-3 @ 107.5% of tap setting
Corridor	138-kV	105.1%	138-kV breakers
DeSoto	138-kV	105.1%	138-kV breakers
East Elkhart	138-kV	105.1%	138-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
East Lima	138-kV	105.1%	138-kV breakers
Fall Creek	138-kV	105.1%	138-kV breakers
Fostoria Central	138-kV	105.1%	138-kV breakers
Galion	138-kV	105.1%	138-kV breakers
Glen Lyn	138-kV	105.1%	138-kV breakers
Grangston	138-kV	105.1%	138-kV breakers
Greentown	138-kV	105.1%	138-kV breakers
Hyatt	138-kV	105.1%	138-kV breakers
Jacksons Ferry	138-kV	105.1%	138-kV breakers
Jackson Road	138-kV	105.1%	138-kV breakers
Joshua Falls	138-kV	105.1%	138-kV breakers
Kammer	138-kV	105.1%	138-kV breakers
Kanawha	138-kV	105.1%	138-kV breakers
Kenzie Creek	138-kV	105.1%	138-kV breakers
Kirk	138-kV	105.1%	138-kV breakers
Leesville	138-kV	105.1%	138-kV breakers
Matt Funk	138-kV	105.1%	138-kV breakers
Muskingum	138-kV	105.1%	138-kV breakers
Nagel	138-kV	105.1%	138-kV breakers
North Proctorville	138-kV	105.1%	138-kV breakers
Ohio Central	138-kV	105.1%	138-kV breakers
Olive	138-kV	105.1%	138-kV breakers
Picway	138-kV	105.1%	138-kV breakers
Reynolds	138-kV	105.1%	138-kV breakers
Roberts	138-kV	105.1%	138-kV breakers
Robison Park	138-kV	105.1%	138-kV breakers
Smith Mountain	138-kV	105.1%	138-kV breakers
Sorenson	138-kV	105.1%	138-kV breakers
South Canton	138-kV	105.1%	138-kV breakers
Southeast Canton	138-kV	105.1%	138-kV breakers
Southwest Lima	138-kV	105.1%	138-kV breakers
Sporn	138-kV	105.1%	138-kV breakers
Tanners Creek	138-kV	105.1%	138-kV breakers
Tidd	138-kV	105.1%	138-kV breakers
Tri State	138-kV	105.1%	138-kV breakers
Twelve Pole	138-kV	105.1%	138-kV breakers
Twin Branch	138-kV	105.1%	138-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
West Bellaire	138-kV	105.1%	138-kV breakers
West Millersport	138-kV	105.1%	138-kV breakers
Wolf Hills	138-kV	105.1%	138-kV breakers
Wyoming	138-kV	105.1%	138-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
Amos	765-kV	100.7%	T3 @ 105.95% of tap setting
Axton	765-kV	105.0%	Shunt reactors
Baker	765-kV	102.4%	T-100 @ 105% of tap setting
Belmont	765-kV	104.6%	T-5 current transformers
Broadford	765-kV	104.6%	765-kV breakers
Cloverdale	765-kV	104.6%	765-kV breakers
Cook	765-kV	102.6%	T-2 @ 108% of tap setting and T-4 @ 105% of tap setting
Culloden	765-kV	104.6%	765-kV breakers
Dumont	765-kV	104.6%	765-kV breakers
Gavin	765-kV	100.7%	T-1 & T2 @ 105.95% of tap setting
Greentown	765-kV	104.5%	T-1 and T-2 110% of tap setting
Hanging Rock	765-kV	104.6%	765-kV breakers
Jacksons Ferry	765-kV	104.6%	765-kV breakers
Jefferson	765-kV	102.4%	T-1 @ 105% of tap setting
Joshua Falls	765-kV	104.6%	765-kV breakers
Kammer	765-kV	99.8%	Mitchell T-1 @ 105% of tap setting
Marquis	765-kV	104.5%	T-1 @ 110% of tap setting
Marysville	765-kV	104.6%	765-kV breakers
Mountaineer	765-kV	100.7%	T-1 @ 105.95% of tap setting
North Proctorville	765-kV	104.5%	T-1 @ 110% of tap setting
Maliszewski	765-kV	104.6%	765 kV breakers
Rockport	765-kV	104.6%	765-kV breakers
South Canton	765-kV	104.5%	T-3 @ 110% of tap setting
Sullivan	765-kV	104.5%	T-1 @ 110% of tap setting
Wyoming	765-kV	104.6%	T-1 and T-2 current transformers
Belmont	500-kV	110.9%	T-1 @ 105% of tap setting
Broadford	500-kV	110.9%	T-4 @ 105% of tap setting
Cloverdale	500-kV	107.1%	T-6A and T-6B @ 105% of tap setting
Jacksons Ferry	500-kV	107.9%	T-1 @ 105% of tap setting
Kammer	500-kV	113.8%	T-200 @ 105% of tap setting
Nagel	500-kV	110.0%	500-kV breakers

Table AII-2
High Voltage Limits During Peak Load Periods

Station		High Voltage Limit	Liability
Allen	345-kV	104.9%	345-kV breakers
Amos	345-kV	104.9%	345-kV breakers
Baker	345-kV	102.4%	Big Sandy T-2 @ 105% of tap setting
Beatty	345-kV	104.9%	345-kV breakers
Benton Harbor	345-kV	111.0%	T-A and T-B @ 110% of tap setting
Bixby	345-kV	104.9%	345-kV breakers
Breed	345-kV	104.9%	345-kV breakers
Canton Central	345-kV	104.9%	345-kV breakers
Clifty Creek	345-kV	103.5%	T-1 through T-6 @ 105.3% of tap settings
Cloverdale	345-kV	104.9%	345-kV breakers
Conesville	345-kV	104.9%	345-kV breakers
Cook	345-kV	104.4%	T-1 @ 105% of tap setting
Corridor	345-kV	104.9%	345-kV breakers
Dequine	345-kV	104.9%	345-kV breakers
DeSoto	345-kV	104.9%	345-kV breakers
Dumont	345-kV	104.9%	345-kV breakers
East Elkhart	345-kV	111.0%	T-2 @ 110% of tap setting
East Lima	345-kV	104.9%	345-kV breakers
Eugene	345-kV	104.9%	345-kV breakers
Fall Creek	345-kV	104.9%	345-kV breakers
Fostoria Central	345-kV	104.9%	345-kV breakers
Galion	345-kV	104.9%	345-kV breakers
Hayden	345-kV	104.9%	345-kV breakers
Hyatt	345-kV	104.9%	345-kV breakers
Jackson Road	345-kV	111.0%	T-3 @ 110% of tap setting
Kammer	345-kV	103.7%	Mitchell T-2 @ 106.4% of tap setting
Kanawha	345-kV	104.9%	345-kV breakers
Kenzie Creek	345-kV	111.0%	T-1 @ 110% of tap setting
Kirk	345-kV	104.9%	345-kV breakers
Kyger Creek	345-kV	104.2%	T-1 through T-5 @ 106% of tap settings
Marquis	345-kV	104.9%	345-kV breakers
Marysville	345-kV	104.9%	345-kV breakers
Matt Funk	345-kV	104.9%	345-kV breakers
Muskingum	345-kV	103.2%	T-2 and T-4 @ 105% of tap setting
Ohio Central	345-kV	108.1%	T-1 @ 110% of tap setting
Olive	345-kV	104.9%	345-kV breakers

Table AII-2 (continued)
High Voltage Limits During Peak Load Periods

Station		High Voltage Limit	Liability
Reynolds	345-kV	111.0%	T-1 @ 110% of tap setting
Roberts	345-kV	111.0%	T-2 @ 110% of tap setting
Robison Park	345-kV	104.9%	345-kV breakers
Sorenson	345-kV	104.9%	345-kV breakers
South Canton	345-kV	104.9%	345-kV breakers
Southeast Canton	345-kV	108.1%	T-1 @ 110% of tap setting
Southwest Lima	345-kV	104.9%	345-kV breakers
Sporn	345-kV	104.9%	345-kV breakers
Tanners Creek	345-kV	104.9%	345-kV breakers
Tidd	345-kV	102.3%	T-3 @ 105% of tap setting
Tri State	345-kV	104.9%	345-kV breakers
Twin Branch	345-kV	104.9%	345-kV breakers
West Bellaire	345-kV	108.1%	T-1 @ 110% of tap setting
West Millersport	345-kV	104.9%	345-kV breakers
Nagel	230-kV	109.6%	T-5 @ 105% of tap setting
Allen	138-kV	104.6%	T-1 @ 105% of tap setting
Amos	138-kV	104.6%	T-7, T-8 and T-9 @ 105% of tap settings
Axton	138-kV	105.1%	T-1 @ 105% of tap setting
Beatty	138-kV	104.6%	T-3 and T-4 @ 105% of tap setting
Benton Harbor	138-kV	104.6%	T-A and T-B @ 105% of tap setting
Big Sandy	138-kV	105.0%	T-1 @ 105% of tap setting
Bixby	138-kV	104.6%	T-1 @ 105% of tap setting
Broadford	138-kV	105.0%	T-1 @ 105% of tap setting
Canton Central	138-kV	104.6%	T-1 and T-2 @ 105% of tap setting
Claytor	138-kV	105.1%	138-kV breakers
Clinch River	138-kV	102.9%	T-1, T-2 and T-3 @ 105% of tap setting
Cloverdale	138-kV	104.6%	T-3B and T-11 @ 105% of tap setting
Conesville	138-kV	102.2%	T-1, T-2 and T-3 @ 105% of tap setting
Corridor	138-kV	104.6%	T-1 @ 105% of tap setting
DeSoto	138-kV	104.6%	T-1 @ 105% of tap setting
East Elkhart	138-kV	104.6%	T-2 @ 105% of tap setting
East Lima	138-kV	104.6%	T-1A, T-1B and T-2 @ 105% of tap setting
Fall Creek	138-kV	104.6%	T-1 @ 105% of tap setting
Fostoria Central	138-kV	104.6%	T-1 @ 105% of tap setting

Table AII-2 (continued)
High Voltage Limits During Peak Load Periods

Station		High Voltage Limit	Liability
Galion	138-kV	106.5%	T-3 and T-4 @ 105% of tap setting
Glen Lyn	138-kV	102.9%	T-6 @ 105% of tap setting
Greentown	138-kV	105.0%	T-1 and T-2 @ 105% of tap setting
Hyatt	138-kV	104.6%	T-1A and T-1B @ 105% of tap setting
Jacksons Ferry	138-kV	105.0%	T-2 @ 105% of tap setting
Jackson Road	138-kV	104.6%	T-3 @ 105% of tap setting
Joshua Falls	138-kV	105.0%	T-1 @ 105% of tap setting
Kammer	138-kV	104.6%	T-100A, T-100B and T-300 @ 105% of tap setting
Kanawha	138-kV	103.2%	T-1 and T-2 @ 105% of tap setting
Kenzie Creek	138-kV	104.6%	T-1 @ 105% of tap setting
Kirk	138-kV	104.6%	T-4 @ 105% of tap setting
Leesville	138-kV	103.2%	T-1 @ 105% of tap setting
Matt Funk	138-kV	104.6%	T-1 @ 105% of tap setting
Muskingum	138-kV	105.1%	138-kV breakers
Nagel	138-kV	105.0%	T-3 @ 105% of tap setting
North Proctorville	138-kV	105.0%	T-1 @ 105% of tap setting
Ohio Central	138-kV	104.6%	T-1 @ 105% of tap setting
Olive	138-kV	104.6%	T-1 and T-2 @ 105% of tap setting
Picway	138-kV	102.4%	T-5 @ 105% of tap setting
Reynolds	138-kV	105.0%	T-1 @ 105% of tap setting
Roberts	138-kV	104.6%	T-2 @ 105% of tap setting
Robison Park	138-kV	104.6%	T-5 @ 105% of tap setting
Smith Mountain	138-kV	103.2%	T-1 and T-5 @ 105% of tap setting
Sorenson	138-kV	104.6%	T-1A, T-1B and T-2 @ 105% of tap setting
South Canton	138-kV	104.6%	T-1 @ 105% of tap setting
Southeast Canton	138-kV	104.6%	T-1 @ 105% of tap setting
Southwest Lima	138-kV	104.6%	T-1 @ 105% of tap setting
Sporn	138-kV	104.6%	T-4 @ 105% of tap setting
Tanners Creek	138-kV	105.1%	138-kV breakers
Tidd	138-kV	102.9%	Cardinal T-1 @ 105% of tap setting
Tri State	138-kV	104.6%	T-1 and T-2 @ 105% of tap setting
Twin Branch	138-kV	104.6%	T-6 @ 105% of tap setting
West Bellaire	138-kV	104.6%	T-1 @ 105% of tap setting
West Millersport	138-kV	104.6%	T-1 @ 105% of tap setting
Wyoming	138-kV	105.0%	T-1 and T-2 @ 105% of tap setting

Table AII-2 (continued)
High Voltage Limits During Peak Load Periods

765 kV Over-voltage Relay Timer Settings

		OVERVOLTAGE TIMER
STATION	CIRCUIT	SETTING
		(MINUTES)
		@1.061p.u.
Amos	Culloden	5.50
	Mountaineer	4.00
	Hanging Rock	5.50
Axton	Jacksons Ferry	4.50
Baker	Broadford	5.00
	Culloden	5.50
	Hanging Rock	4.50
Broadford	Baker	5.00
	Jacksons Ferry	4.50
Cloverdale	Jacksons Ferry	4.50
	Joshua Falls	4.00
Cook	Dumont	4.00
Culloden	Amos	5.50
	Baker	5.50
	Gavin	4.50
	Wyoming	5.50
Dumont	Cook	4.00
	Greentown	5.00
	Marysville	4.50
	Wilton Center	5.50
Gavin	Culloden	4.50
	Marysville	6.00
	Mountaineer	5.50
Greentown	Dumont	5.00
	Jefferson	5.50
Hanging Rock	Amos	5.50
	Baker	4.50
	Jefferson	4.00
	Marquis	5.00
Jacksons Ferry	Axton	4.50
	Broadford	5.00
	Cloverdale	5.50

	Wyoming	4.00
Jefferson	Greentown	5.50
	Hanging Rock	4.00
	Rockport	6.00
Joshua Falls	Cloverdale	4.00
Kammer	Maliszewski	5.00
	Mountaineer	4.50
	South Canton	5.50
Marquis	Hanging Rock	5.00
Marysville	Dumont	4.50
	Gavin	6.00
	Maliszewski	5.00
Mountaineer	Amos	4.00
	Gavin	5.50
	Kammer	4.50
Maliszewski	Kammer	4.50
	Marysville	5.50
Rockport	Jefferson	6.00
	Sullivan	5.50
South Canton	Kammer	5.50
Sullivan	Rockport	5.50
Wyoming	Culloden	5.50
	Jacksons Ferry	4.00

Table AII-3
Location and Time Delay Setting of Overvoltage Relays

Circuit Breaker Type	**kV**	**Continuous**	**30 Minute**	**2 Hour**	**24 Hour**
All types	138	145 kV (1.051 pu)	146 kV (1.058 pu)	146 kV (1.058 pu)	146 kV (1.058 pu)
	345	362 kV (1.049 pu)	(see below)	(see below)	(see below)
	500	550 kV (1.10 pu)			
	765	800 kV (1.046 pu)	(see below)	(see below)	(see below)
765 kV CBs w/o free standing Oil filled CTs	765	800 kV (1.046 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)
765 kV CBs with free standing Oil filled CTs	765	800 kV (1.046 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)
345 kV SF6 puffer CBs w/o free standing Oil filled CTs	345	362 kV (1.049 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)
345 kV air blast CBs w/o free standing Oil filled CTs	345	362 kV (1.049 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)
345 kV CBs with free standing Oil filled CTs	345	362 kV (1.049 pu)	396 kV (1.148 pu)	373 kV (1.081 pu)	362 kV (1.049 pu)
345 kV Oil CBs	345	362 kV (1.049 pu)	372 kV (1.078 pu)	372 kV (1.078 pu)	372 kV (1.078 pu)

Table AII-4
High Voltage Limits for Circuit Breakers

Appendix III

Under Frequency Guidelines – AEP/PJM

1. At 59.75 Hz
    a. Suspend Automatic Generation Control (AGC)
    b. Notify Interruptible Customers to drop load
2. At 59.5 Hz automatically shed 5 % System internal load by relay action. (25 cycle, .42 sec. delay)
3. At 59.3 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. Delay)
4. At 59.1 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
5. At 58.9 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
6. At 58.7 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
7. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.
8. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Criteria

1. Total load to be controlled by load shedding relays should equal a minimum of 25 % of System Internal Load.
2. The Trip Time Delay should be 25 cycles (.42 seconds)
3. The Restoration Frequency should be:
    a. 59.95 Hz — For non-supervisory controlled stations and remote/rural area feeders.
    b. Disabled — For supervisory controlled stations and feeders, or stations and feeders located in a metropolitan area with a 15 minute or less response time
4. The Block Voltage should be set at 75%; which is 90 volts on a 120 volt base.

The Integrated and Straight Timer settings are as follows:

Load Restored	Integrated Time at or above 59.95 Hz	Straight Time at 59.95 Hz
1st Block - 1%	4 minutes	1 seconds
2nd Block - 1%	4 minutes	2 seconds
3rd Block - 1%	4 minutes	3 seconds
4th Block - 1%	6 minutes	4 seconds
5th Block - 1%	6 minutes	5seconds
6th Block - 1%	6 minutes	6 seconds
7th Block - 1%	8 minutes	7 seconds
8th Block - 1%	8 minutes	8 seconds
9th Block - 1%	8 minutes	9 seconds
10th Block - 1%	8 minutes	10 seconds
11th Block - 1%	10 minutes	11 seconds
12th Block - 1%	10 minutes	12 seconds
13th Block - 1%	10 minutes	13 seconds
14th Block - 1%	10 minutes	14 seconds
15th Block - 1%	10 minutes	15 seconds
16th Block - 1%	12 minutes	16 seconds
17th Block - 1%	12 minutes	17 seconds
18th Block - 1%	12 minutes	18 seconds
19th Block - 1%	12 minutes	19 seconds
20th Block - 1%	12 minutes	20 seconds
21st Block - 1%	14 minutes	21 seconds
22nd Block - 1%	14 minutes	22 seconds
23rd Block - 1%	14 minutes	23 seconds
24th Block - 1%	14 minutes	24 seconds
25th Block - 1%	14 minutes	25 seconds

Note: An additional 30 second integrated timer setting is normally applied to the older style mechanical relays.

Estimated AEP/PJM Mw load shed in each step, based on summer forecast 2017 data:

AEP East Summer Peak Load		**22945**	Mws	Summer Forecast 2017			
Company		**59.5**	**59.3**	**59.1**	**58.9**	**58.7**	TOTAL
	PJM REGION 2014 PEAK	5.00%	5.00%	5.00%	5.00%	5.00%	25.00%
Appalachian		314	438	465	358	443	2018
Columbus Southern Power		383	213	305	366	323	1590
Indiana Michigan		313	278	280	306	368	1545
Kentucky		85	83	143	80	124	515
Kingsport		40	47	29	15	21	152
Ohio Power		214	339	268	423	359	1603
Wheeling Power		0	0	52	2	0	54
	TOTAL	1349	1398	1542	1550	1638	
	PERCENT	**5.88%**	**6.09%**	**6.72%**	**6.76%**	**7.14%**	32.59%

A listing of Under-Frequency circuits is on file at the TDC's.

Under Frequency Guidelines – AEP/SPP

1. At 59.75 Hz
    a. Suspend Automatic Generation Control (AGC)
    b. Notify Interruptible Customers to drop load
2. At 59.3 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
3. At 59.0 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
4. At 58.7 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
5. At 58.5 Hz isolate into islands in both PSO and SWEPCO (15 cycle, .25 sec. delay)
    a. PSO - 3 Islands, Refer to PSO UF plan for island boundaries
    b. SWEPCO – 3 Islands, Refer to SWEPCO UF plan for island boundaries.
6. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Criteria

1. Total load to be controlled by load shedding relays should equal a minimum of 30 % of System Internal Load.
2. The intentional relay trip delay should be set at 15 cycles (0 .25 seconds)
3. The Under-voltage inhibit should be set at 80%; which is 96 volts on a 120 volt base.
4. Current supervision can be used in locations where sizable motor load could cause relay misoperations.
5. Automatic reclosing shall be disabled for loads that are tripped by under-frequency. Delayed automatic restoration of load may be allowed under certain conditions.

Estimated AEP/SPP Mw load shed in each step, based on summer peak load data:

PSO Summer Peak Load	2017	**3825**	Mws			
Distribution Region		59.3	59	58.7	Steps 1-2	Steps 1-3
		10.00%	10.00%	10.00%		30.00%
Eastern		63	83	42	146	188
Northern		57	42	46	99	145
Tulsa		217	257	362	474	836
Western		127	80	74	207	281
	TOTAL	464	462	524	926	
	PERCENT	**12.13%**	**12.08%**	**13.70%**	**24.21%**	**37.91%**

SWEPCO Summer Peak Load	2017	**4303**	Mws			
Distribution Region		59.3	59	58.7	Total for Steps 1-2	Total 3 Steps
		10.00%	10.00%	10.00%	20-25%	30.00%
Central		116	77	84	193	277
Northern		90	60	65	150	215
Southern		161	173	146	334	480
Western		107	118	132	225	357
West LA		23	21	0	44	44
West TX		3	0	6	3	9
Municipal		0	0	0	0	0
	TOTAL	500	449	433	949	
	PERCENT	**11.62%**	**10.43%**	**10.06%**	**22.05%**	**32.12 %**

A listing of Under-Frequency circuits is on file at the TDC's

Appendix IV

AEP East/PJM - Voltage Reduction Guidelines

As indicated in Section 2 of PJM manual 13, AEP does not have a Voltage Reduction Program.

AEP West/SPP - Voltage Reduction Guidelines

At the present time, a voltage reduction program for AEP/SPP does not exist. This is not a wide spread practice among Control Areas in the SPP region.

Appendix V

AEP East/PJM - Manual Load Shedding Guidelines

The Manual Load Shedding Program is part of the Emergency Operating Plan, as AEP may have a need to shed load to preserve the integrity of the interconnected system. This plan is usually activated for a Capacity Deficiency or a Transmission Emergency event. The AEP-Dominion Interface IROL procedure also includes load shedding as an option. Refer to the IROL Relief Procedures AEPE PJM pdf document located on the TOPS ShareNow site for additional details at Engineering>Operating Guidelines>AEP East>General.

Manual load shedding is performed in the AEP East/PJM footprint by arming the AEP Advanced Load Shedding (ALS) program which opens a pre-defined set of distribution feeder breakers to achieve a desired load shed objective. Once the objective is achieved, the program cycles though the breaker list by closing an open breaker followed by opening up another breaker. The program also monitors the total load shed against the load shed objective in order to continuously maintain the requested amount of load shed.

The Menu Advanced Load Shedding (MALS) displays on the COTDC and ROTDC ADX systems show the MVA load shed available for each area. The LOAD displayed in the figures below reflects the current real time area load.

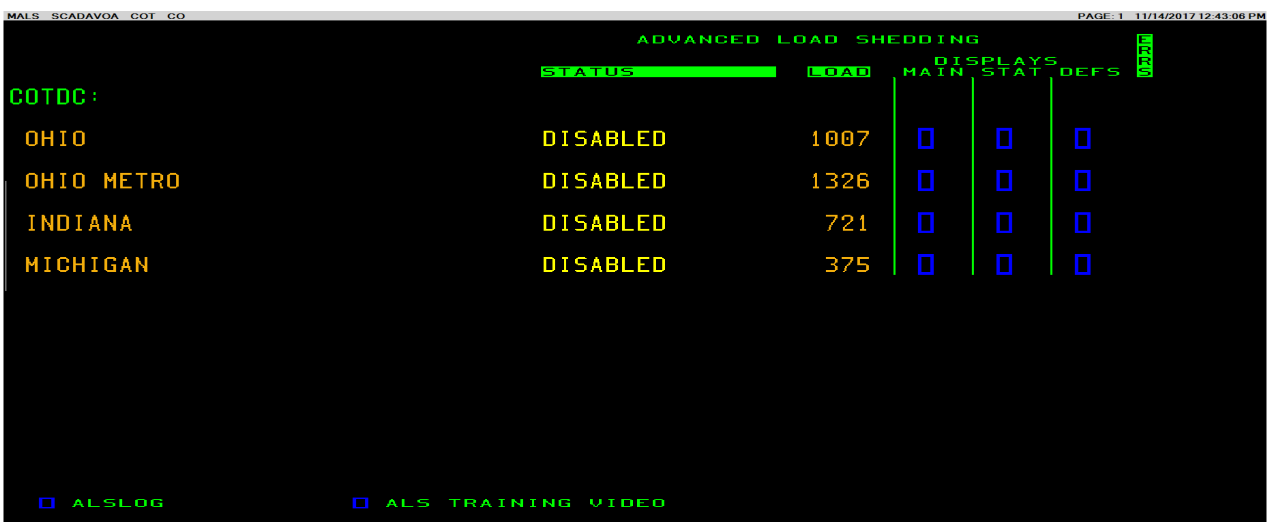

Figure AV-1 - MALS Display for COTDC System

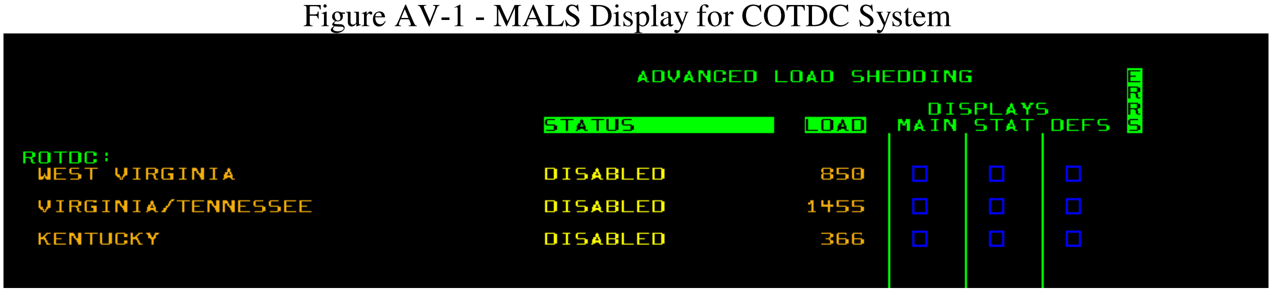

Figure AV-2 - MALS Display for ROTDC System

As an example using the MALS display for the COTDC System, upon selecting OHIO, the program directs the user to the OHIO Control screen.

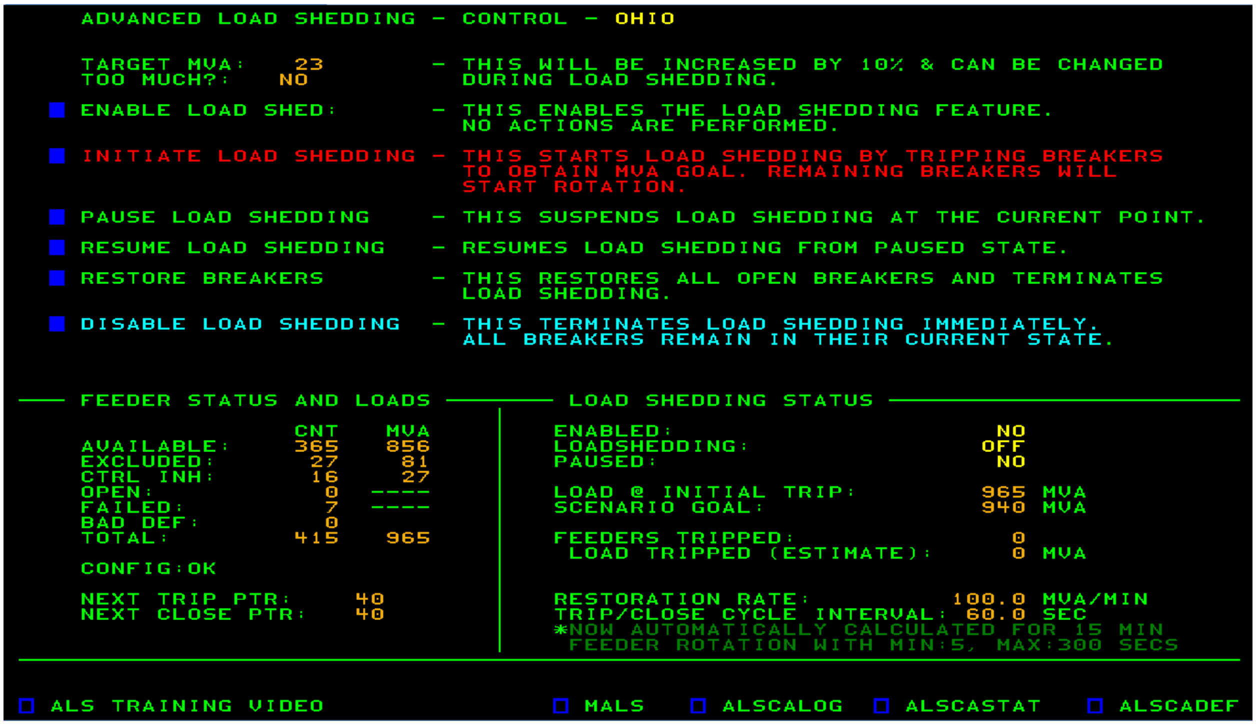

Figure AV-3 - ALSCA Display

From a high level perspective, to shed load the TDC:

1. Enters the TARGET MVA load to shed
2. Selects Enable Load Shed poke point
3. Selects Initiate Load Shedding followed by Confirm

The attached link to the ALS training video provides detailed step by step instructions on the program. http://topsweb/Videos/ALS/ALS%20for%20Dispatchers.html

Peak Non coincidental MW Available on MALS for calendar year 2016						
ALS by TDC	**CCTDC**	**CETDC**	**CWTDC**	**RNTDC**	**RSTDC**	**Total**
MW's Available for ALS	3,596	1,029	2,121	2,662	1,908	11,316

Table AV-1

The following sequence shows the events that will take place:

The SCC will issue a Mandatory Load Curtailment Alert. Each TDC will identify predetermined load area to be utilized for manual load shedding

The SCC will issue a Mandatory Load Curtailment Warning. Each TDC will arm a predetermined area to stand by for Manual Load Curtailment.

The final step is for the SCC to issue the order Execute Mandatory Load Curtailment. The SCC will advise each TDC to initiate Mandatory Load Curtailment on the requested amount of load in their specific area through the use of the manually armed ALS program.

Load Shedding Criteria

The circuits should be prioritized by the following guidelines. These guidelines have been approved by Legal and meet the State requirements for the definition of "Priority Use". We will shed Priority 3 circuits first, then Priority 2, and if more load is needed, even Priority 1. We will need to select stations that have at least 2 feeders and each feeder should have at least 3,000 kW of load. Stations with supervisory control and meeting the above criteria should be selected since we can ultimately utilize them in a computer program. We need to shed at least 25 % of the Operating Company's peak summer/winter internal load. (12.5 % Group A, 12.5 % Group B)

Priority The feeders selected for use in controlled rotating blackouts are prioritized as follows:

Priority 1 - "Hospitals" which shall be limited to major institutions providing critical care to patients

Priority 2 - Police, fire, communication services, water and sewer services, government, transportation, emergency medical services, alternate energy and food services.

Priority 3 - All other customers

The following abbreviations can be used to describe the type of load on each circuit and in many cases the same circuit will have several priority users.

Abbreviation	***Definition***
HOSP	Hospitals
LS	Life support equipment
POL	Police stations and Government detention institutions
EMS	Emergency medical services
GOVT	Critical State and Federal government facilities
FIRE	Fire stations
COM	Communication services; i.e. telephone, radio, newspaper
WATER	Water and/or sewer services
TRAN	Transportation related services; i.e. transit systems, major airport terminals
ALT ENG	Alternate energy source services; i.e. IPP, Cogen
FOOD	Perishable food or medicine that represents substantially all of a customers load

Due to the vast number of distribution circuits with life support; if a circuit only has life support on it, it should be classified as a Priority 3. The life support equipment is required to have a backup power supply and will ride through any of the abnormal circuit outages we experience every day. That being the case, the planned rotation should not pose a problem.

The amount of load to be shed in each District should be in the same proportion as the District load is to the Operating Company's peak summer/winter internal load. That being the case, we need to make some estimate of what percentage the District load is to the Operating Company's peak summer/winter internal load. Keep in mind that we are to be nondiscriminatory in the load we shed.

Procedure:

1. Estimate % District load as a percentage of Operating Companies peak summer/winter internal load and calculate target load for summer and winter.
   (Target Load = % District Load x Operating Company peak load x 25 %)
2. Determine type of load on each Districts circuits and assign a Priority number.
3. Add the Priority 3 circuit loads and compare to target load for the District.
4. If Priority 3 circuits are not enough, select Priority 2 circuits and recalculate.
5. If Priority 2 circuits are not enough, select Priority 1 circuits and recalculate.

AEP West/SPP - Manual Load Shedding Guidelines

PSO Plan

Feeders are grouped in 8 Steps labeled "A" through "H". Each Step represents approximately 5% of the PSO summer peak load. The SCC will determine when it is necessary to put this plan into effect and will notify the Tulsa Transmission Dispatch Center (TDC). The Tulsa TDC would then coordinate with the Distribution Dispatch Center (DDC) who would implement load shedding. The feeders within each Step have supervisory control and can be operated individually from the DDC allowing load to be shed in increments up to the total load for the Step Each Step would take approximately 3-5 minutes to implement. The feeder rotation will be carried out in one-hour intervals. The objective of this plan is to have no circuits open more than two hours.

Division	Transmission Customers	Step A MW	Step B MW	Step C MW	Step D MW	Step E MW	Step F MW	Step G MW	Step H MW
Tulsa Urban (south)	134	75	80	68	80	64	70	71	75
Tulsa Rural (north)	27	12	14	11	12	6	8	6	5
McAlester	36	15	14	12	10	10	12	9	8
Lawton	48	20	27	20	20	19	21	13	13
PSO Native Total	245	122	135	112	123	99	111	99	101

Notes:

- The PSO automatic load transfer in the Step is placed on manual during a manual load shed event which inhibits load transfer to the alternate source.
- The TDC "Manual Load Shed PSO" plan on the TOps ShareNow >TDC> Tulsa>Emergency Plans> contains a list of the load shedding feeders.

SWEPCo Plan

The SWEPCo plan has 6 Steps labeled A through F consisting of distribution feeders. Each distribution Step represents approximately 5 % of SWEPCo's peak internal load. Some of the Steps have supervisory control, and others will require manual load shedding by sending personnel to the station to rotate the feeders. Typically, Steps A, B & C are supervisory control from the DDC allowing load to be shed in increments up to the total load for the Step, and Steps D, E & F are a mixture. Each supervisory Step would take approximately 3-5 minutes to implement. The feeder rotation will be done similar to PSO on a one-hour interval. The objective of this plan is to have no circuits open more than two hours.

The summer peak Mw breakdown is as follows:

Division	Customers	Step A MW	Step B MW	Step C MW	Step D MW	Step E MW	Step F MW
Southern	74484	84.2	87.4	84.6	70.7	80.5	81.4
Western	35000	51.1	51.2	47.9	51.8	53	48.3
Central- TX	19206	23.4	22.4	27	26.2	34	24.7
Northern	29370	40.5	34.8	35.7	33.5	39	36.9
Central- AR	13457	12.3	16.1	13.2	17.4	10.5	15.2
TOTAL --	171517	211.6	211.9	208.3	199.6	216.9	206.4

The TDC "Manual Load Shed SWEPCO" plan on the TOps ShareNow >TDC>Shreveport>Emergency Plans> contains a list of the load shedding feeders.

The following sequence shows the events that will take place:

The SCC will issue a <u>Mandatory Load Curtailment Alert.</u> Each TDC will identify predetermined stations to be utilized for manual load shedding

The SCC will issue a <u>Mandatory Load Curtailment Warning.</u> Each TDC will dispatch personnel to predetermined stations to stand by for Manual Load Curtailment, and\or prepare to shed load on the SVC controlled circuits via the SCADA systems. One person will be dispatched to handle only one station since this will minimize outages during the restoration procedure. In addition, each person assigned to a station must maintain communications with the TDC.

The final step is for the SCC to issue the order <u>Execute Mandatory Load Curtailment</u>. Each TDC will advise personnel to initiate Mandatory Load Curtailment as indicated in their station listings, and\or carryout the load shedding on the SVC controlled circuits via the SCADA systems.

NERC EOP 011-1 requirement R1.2.5 states in part:

> Processes to prepare for and mitigate Emergencies including **provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency…**

AEP approaches this requirement by avoiding the addition new manual load shed facilities that have automatic Load shedding.

Appendix VI

Purpose:

The Operator Authority to Act Policy document outlines the Responsibilities and Authorities of AEP Transmission System Control Center Operators and Transmission Dispatchers in performing various actions to alleviate operating emergencies and / or ensure stable and reliable operation of the AEP transmission system.

Revision 7 of the Operator Authority to Act Policy document follows:

TRANSMISSION OPERATIONS

Operator Authority to Act Policy

Revision 7

December 13, 2016

Table of Contents

Document Control

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Approvals

NAME	TITLE	SIGNATURE / DATE
Paul Johnson	Managing Director, Transmission Operations	Paul Johnson 12/13/16 D.S.

Review Cycle

Quarterly	Semi-annual	Annual	**Triennial X**

Retention Period

Six months	One Year	Two Years	**Three Years X**

Release

VERSION	DATE	FILE NAME	CHANGE NOTICE
Revision 0.0	February 23, 2004	Operator Authority to Act Policy.pdf	Original statement granting authority, including load shedding as per CERC Operating Policy 8A
Revision 1.0	November 21, 2005	Operator Authority to Act Policy V1.pdf	Revised to reference NERC Standard PER-001-0
Revision 2.0	March 26, 2007	Operator Authority to Act Policy V2.pdf	Revised per Dec 2006 gap analysis, added reference to NERC Standard TOP-001-1 and added hierarchal operating authority and endorsements
Revision 3.0	January 27, 2009	Operator Authority to Act Policy V3.pdf	Added Paul Johnson as signee
Revision 4.0	April 25, 2011	Operator Authority to Act Policy V4.pdf	Minor NERC PER-001-0.1 update. Added approvals

Revision 5.0	October 17, 2012	Operator Authority to Act Policy V5.pdf	Reflecting NERC PER-001-0.2 and TOP-001-1a updates. Added PER-003-1 reference and clarified acknowledging of supplemental communications.
Revision 6.0	April 2, 2015	Operator Authority to Act Policy V6.pdf	Triennial Review. Updated NERC Standard references and NERC definitions included references to RC and TO/TOP authority documents in each region.
Revision 7.0	December 13, 2016	Operator Authority to Act Policy V7.pdf	Triennial Review. Updated NERC Standard references and NERC definitions for Operating Instructions. Removed references to directives.

References

<u>NERC Reliability Standards:</u>

PER-001-0.2: Operating Personnel Responsibility and Authority
PER-003-1: Operating Personnel Credentials
TOP-001-1a: Reliability Responsibilities and Authorities
TOP-001-3: Transmission Operations
IRO-001-1.1: Reliability Coordination – Responsibilities and Authorities
IRO-001-4: Reliability Coordination – Responsibilities
IRO-004-2: Reliability Coordination – Operations Planning

PJM Manual 3: Transmission Operations, Section 1: Transmission Operations Requirements
PJM TO/TOP (Transmission Owner/Transmission Operator) Matrix
Southwest Power Pool Operating Criteria, Section 4.1Responsibility and Authority
ERCOT Coordinated Functional Registration Agreement and Matrix

The referenced NERC Reliability Standards and RTO manuals and matrices outline specific requirements pertaining to operating personnel responsibility and authority in taking actions to alleviate operating Emergencies, Adverse Reliability Impacts, as well as, complying with Operating Instructions.

Key Terms and Definitions

Adverse Reliability Impact [NERC] - The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.

Emergency - Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Operating Instruction - A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

Purpose and Overview

This policy outlines the Responsibilities and Authorities of AEP Transmission System Control Center Reliability Coordinators and Transmission Dispatchers in performing various actions to alleviate operating Emergencies and / or ensure stable and reliable operation of the AEP transmission system,

This policy establishes operating responsibilities and authorities to maintain the safety and reliability of the AEP transmission system. Supplemental communications from engineering personnel, equipment specialists, field personnel, immediate supervision and management or any others may be acknowledged but shall not alter the responsibility and authority of Transmission System Control Center Reliability Coordinators and Transmission Dispatchers in performing actions required to maintain the safety and reliability of the AEP transmission system.

Policy

1. Transmission System Control Center Reliability Coordinators and Transmission Dispatchers hereby have the responsibility and authority to take or direct whatever actions are needed in real-time to maintain safety and reliability. These actions include, but are not limited to, re-dispatch generation, reconfigure transmission, or reducing firm load to alleviate operating Emergencies and/or to ensure the stable and reliable operation of the AEP transmission system. These actions do not require any prior approval from higher-level personnel within AEP.

2. The Transmission System Control Center Reliability Coordinators are the highest real-time operating authority within AEP, except for the ERCOT Region, where the Transmission Dispatcher is the highest authority.

   For AEP within the PJM and SPP Regions:

   a. The Transmission System Control Center Reliability Coordinators shall comply with all Operating Instructions issued by the applicable NERC Reliability Coordinator (PJM for AEP facilities in the east or SPP for AEP facilities in the west external to ERCOT), unless such action(s) cannot be physically implemented or would violate safety, equipment, regulatory or statutory requirements. If such an Operating Instruction cannot be complied with, the Transmission System Control Center Reliability Coordinator shall immediately inform the PJM or SPP Reliability Coordinator of the inability to perform the Operating Instruction so alternate remedial actions can be implemented.

   b. All Generation Dispatchers and Transmission Dispatchers shall comply with all Operating Instructions issued by the Transmission System Control Center Reliability Coordinator, unless such action(s) cannot be physically implemented or would violate safety, equipment, regulatory or statutory requirements. If such an Operating Instruction cannot be complied with, the Generation Dispatchers and/or Transmission Dispatchers shall immediately inform the Transmission System Control Center Reliability Coordinator of the inability to perform the Operating Instruction so alternate remedial actions can be implemented.

   c. All Distribution Dispatchers shall comply with all Operating Instructions issued by the Transmission Dispatcher, unless such action(s) cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. If such an Operating Instruction cannot be complied with, the Distribution Dispatchers shall immediately inform the Transmission Dispatcher of the inability to perform the Operating Instruction so that the Transmission Dispatcher can implement alternate remedial actions.

For AEP within the ERCOT Region:

a. The Transmission Dispatcher within ERCOT shall comply with all Operating Instructions issued by the ERCOT Reliability Coordinator, unless such action(s) cannot be physically implemented or would violate safety, equipment, regulatory or statutory requirements. If such an Operating Instruction cannot be complied with, the Transmission Dispatcher shall immediately inform the ERCOT Reliability Coordinator of the inability to perform the Operating Instruction so that the ERCOT Reliability Coordinator can implement alternate remedial actions.

b. The Generation Dispatchers and Distribution Dispatchers shall comply with all Operating Instructions issued by the Transmission Dispatcher, unless such action(s) cannot be physically implemented or would violate safety, equipment, regulatory or statutory requirements. If such an Operating Instruction cannot be complied with, the Generation Dispatchers and/or Distribution Dispatchers shall immediately inform the Transmission Dispatcher of the inability to perform the Operating Instruction so that the Transmission Dispatcher can implement alternate remedial actions.

Appendix VII

Internal Contacts[1]

Region	Name	JobTitle	Direct	Audinet	AEP Cell Phone
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TX	Murphy, J S (Joel)	Dir Customer Svcs & Mktg	[redacted]	[redacted]	[redacted]
TX	Hughes Gilbert	Director Regulatory Svcs	[redacted]	[redacted]	[redacted]
Environment	**McManus,John M**	**VP - Environmental Services**	[redacted]	[redacted]	[redacted]
Environment	Hendricks,John C	Director-Air Quality Services	[redacted]	[redacted]	[redacted]
Environment	Wood,Alan R	Director-Water Quality	[redacted]	[redacted]	[redacted]
Commercial Operations	**Thompson, William R**	**Director Real Time Market Opers**	[redacted]	[redacted]	[redacted]
Commercial Operations	Robert A Beller	Dir-Day Ahead RTO Ops	[redacted]	[redacted]	[redacted]

AEP East/PJM Region Neighboring System Contacts[2]

Company	IC	Group Email
PJM Valley Forge Power Diaptcher	[redacted]	[redacted]
PJM Valley Forge Reliability Engineer	[redacted]	[redacted]
PJM Valley Forge Generation Dispatcher	[redacted]	[redacted]
PJM Milford Power Dispatcher	[redacted]	[redacted]
PJM Milford Reliability Engineer	[redacted]	[redacted]
PJM Milford Generation Dispatcher	[redacted]	[redacted]
MECS	[redacted]	[redacted]
TVA Balancing Authority	[redacted]	[redacted]
TVA North Transmission	[redacted]	[redacted]
AMRN	[redacted]	[redacted]
Buckeye Power	[redacted]	[redacted]
ComEd	[redacted]	[redacted]
DLCO	[redacted]	[redacted]
Dayton Power & Light	[redacted]	[redacted]
Duke Carolina/Progress (CPL)	[redacted]	[redacted]
Duke East (Carolina)	[redacted]	[redacted]
Duke MidWest (Ohio/Kentucky)	[redacted]	[redacted]
EKPC	[redacted]	[redacted]
Indiana Power & Light	[redacted]	[redacted]
FE Central	[redacted]	[redacted]
FE South	[redacted]	[redacted]
FE West	[redacted]	[redacted]
Hoosier Energy Trans	[redacted]	[redacted]
Hoosier Energy Generation	[redacted]	[redacted]
ITC	[redacted]	[redacted]
LGEE (KU) Trans	[redacted]	[redacted]
LGEE (KU) Balancing	[redacted]	

Company	IC	Group Email
Authority		
LGEE (LGE)	[redacted]	[redacted]
NIPSCO	[redacted]	[redacted]
OVEC	[redacted]	[redacted]
VP/Dominion	[redacted]	[redacted]
Blue Creek Wind Farm (AVANGrid)	[redacted]	[redacted]
Fowler Ridge Wind Farm	[redacted]	[redacted]
Headwaters Wind Farm (EDPR)	[redacted]	[redacted]
Wildcat EON Wind Farm	[redacted]	[redacted]
Meadow Lake Wind Farm (EDPR)	[redacted]	[redacted]
Timber Road Wind Farm (EDPR)	[redacted]	[redacted]
AMPO (Gorsuch) RETIRED	[redacted]	[redacted]
Big Sandy IPP (MRP)	[redacted]	[redacted]
Dynegy (Hanging Rock)	[redacted]	[redacted]
Dynegy (Washington)	[redacted]	[redacted]
Dynergy (Beverly and Hanging Rock) Gen Dispatch	[redacted]	
DPLE (Keystone)	[redacted]	[redacted]
ENEL North America Fries Hydro	[redacted]	[redacted]
FE Buchanan	[redacted]	[redacted]
GRPP Summersville (Tower117)	[redacted]	[redacted]
IMPA (Anderson/Richmond)	[redacted]	[redacted]
Montpelier Keystone (DP&L)	[redacted]	[redacted]
Mayflower	[redacted]	[redacted]
Mirant (Sugar Creek)	[redacted]	[redacted]
Riverside & Foothills	[redacted]	[redacted]
Rolling Hills CAMS (Flatlick)	[redacted]	[redacted]
RP Mone	[redacted]	[redacted]
Sun Coke	[redacted]	
Tenaska (Wolf Hills)	[redacted]	[redacted]

AEP West/SPP Region Interconnection / External Entity Contact List[2]

Company	IC	Group Email Address
AECC - Fitzhugh	[redacted]	[redacted]
AECC (GOP)	[redacted]	[redacted]
AECC (TO plus the 17 CO-OP DP members)	[redacted]	[redacted]
AECI	[redacted]	[redacted]
Blue Canyon Windfarm (Psuedo Tie to WFEC)	[redacted]	[redacted]
CAJUN (LAGEN)	[redacted]	[redacted]
CLECO	[redacted]	[redacted]
Cogentrix IPP (aka Greencountry)	[redacted]	[redacted]
Dempsey Ridge Windfarm	[redacted]	[redacted]
EDE	[redacted]	[redacted]
Elk City Windfarms (Nextera)	[redacted]	[redacted]
ERCOT East DC Tie Operator	[redacted]	[redacted]
ERCOT North DC Tie Operator	[redacted]	
ESI	[redacted]	[redacted]
ETEX Cogeneration	[redacted]	[redacted]
Gateway IPP	[redacted]	[redacted]
GRDA	[redacted]	[redacted]
HCPP IPP	[redacted]	[redacted]
KGE-WR	[redacted]	[redacted]
Kiowa IPP	[redacted]	[redacted]
MISO South - Little Rock	[redacted]	[redacted]
Narrows Dam (Units 1, 2 and 3)	[redacted]	[redacted]
OGE	[redacted]	[redacted]

Company	IC	Group Email Address
OMPA	[redacted]	[redacted]
ONETA IPP (Calpine)	[redacted]	[redacted]
Rocky Ridge Windfarm	[redacted]	[redacted]
Rush Springs Windfarms (Nextera)	[redacted]	[redacted]
Sleeping Bear Windfarm	[redacted]	[redacted]
SPA	[redacted]	[redacted]
SPS	[redacted]	[redacted]
SPP BA	[redacted]	[redacted]
SPP Engineer	[redacted]	[redacted]
SPPRC	[redacted]	[redacted]
US Steel (Lonestar Steel)	[redacted]	
Weatherford Wind - Florida (FPDC)	[redacted]	[redacted]
WFEC	[redacted]	

Notes:
This contact information is current as of 12/26/2017 but it is subject to change.

1. Refer to the AEP Microsoft Outlook email client which contains the current internal contact information details.
2. Refer to AEP SCC external contact lists which contain the current external contact information details.