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May 26, 2005

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RECEIVED
MAY 26 2005
PUBLIC SERVICE COMMISSION

HAND DELIVERED

Beth O' Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
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Frankfort, Kentucky 40602-0615

RE: 2005-00090

Dear Ms. O'Donnell:

Please find and accept for filing a redacted copy of the filing previously made by Kentucky Power Company in the above proceeding. As directed in your May 2, 2005 letter the critical electrical infrastructure information has been redacted from the filing.

Because of the size of the filing and the number of parties a copy of the redacted filing is not being provided to the parties in this proceeding.

Sincerely yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

Enclosure
cc: Parties of Record (without enclosure)

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This is the Service List for Case 2005-00090

Jonathan H Riley

05/25/2005 03:42 PM

To: Errol K Wagner/AS1/AEPIN@AEPIN
cc: Paul B Johnson/OR4/AEPIN@AEPIN, Albert M Yockey/OR4/AEPIN@AEPIN, Beverly B Laios/OR4/AEPIN@AEPIN
Subject: redacted versions of confidential reports filed re:Kentucky Administrative Case 2005-00090

Errol:

Attached is a Zipped file containing the redacted versions of the study reports listed below. The original reports contained information which is considered Critical Energy Infrastructure Information (CEII). The CEII content has either been blacked out or deleted in the versions provided here.

Please note although the CEII content will appear blacked out when viewing the information on-screen, the setting of one of the print options is critical for it to remain blacked out in the printed copy which you will be filing.

The "Print What:" selection (lower left in the print pop up window) MUST be set to "Document and Comments" or the material intended to be blacked out will be visible. I also suggest spot-checking one or two printed pages from each report against the on-screen version to ensure that the CEII material is actually obscured. Because of the potential that the redacting in the electronic files could be reversed, I would also ask that once you are sure that you have the necessary hardcopy printed, you delete the electronic version. We will maintain an electronic copy here for any future needs.

I'm also attaching a file that shows the correct printer setting. Please call me if you have any questions.

The reports included are:
- 2004 AEP FERC Form 715 filing
- 2004/5 Winter AEP Bulk System Performance Appraisal
- 2004 Summer AEP Bulk System Performance Appraisal
- 2004 Summer ECAR Transmission System Performance report
- 2004 Summer VEM
- 2004 Summer MET

2004 Summer VAST
2009 Summer AEP Transmission Assessment

print set.pdf all redacted.zip

J. H. Riley
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AMERICAN ELECTRIC POWER*

FERC FORM 715 – ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

2004 FILING

* **Filed by American Electric Power on behalf of:**

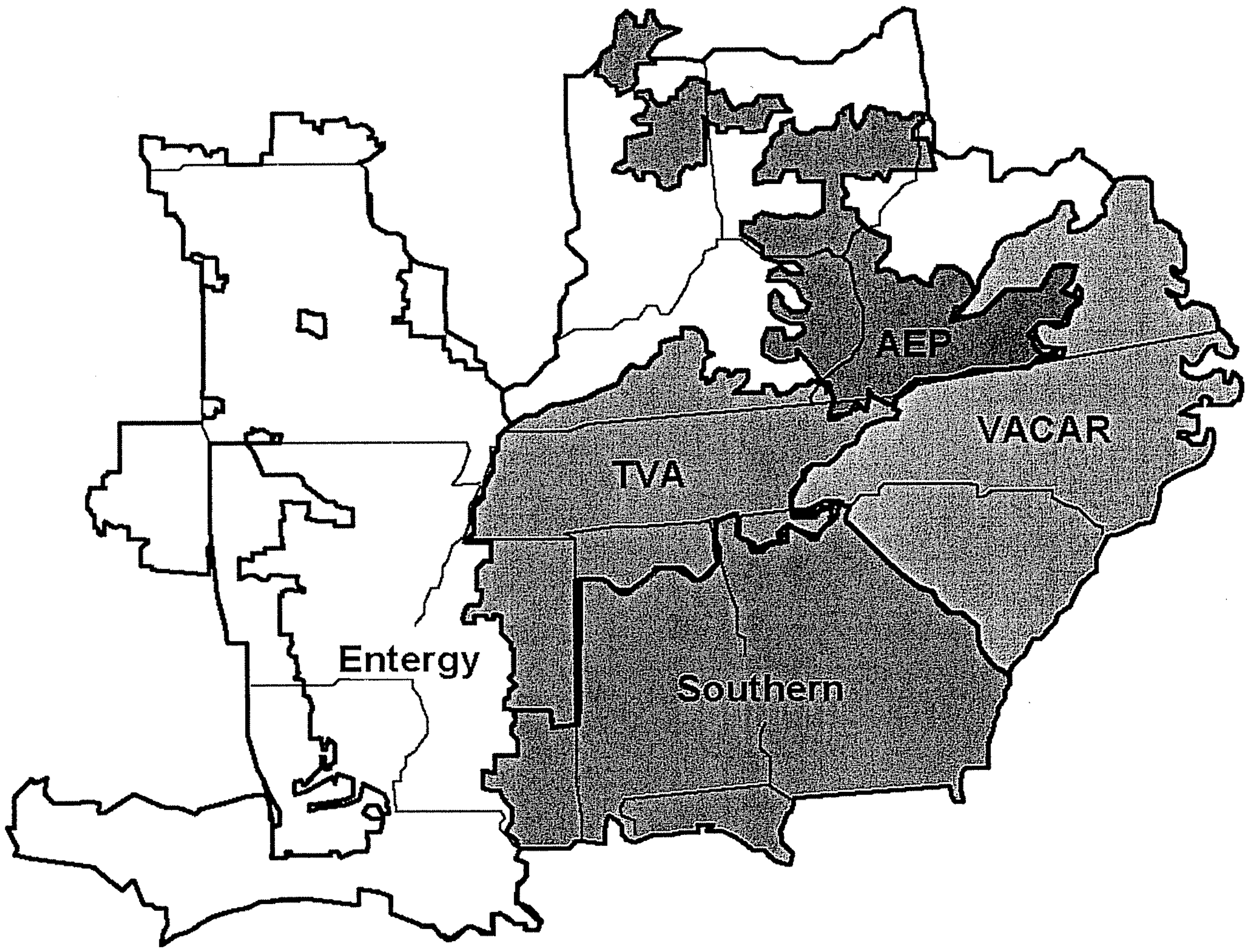
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Wheeling Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company

The contents of this document consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

VACAR-AEP-SOUTHERN-TVA-ENTERGY STUDY GROUP

2004 SUMMER RELIABILITY STUDY OF PROJECTED OPERATING CONDITIONS



2004 Summer

VACAR-AEP-SOUTHERN-TVA-ENTERGY STUDY GROUP

2004 SUMMER RELIABILITY STUDY OF PROJECTED OPERATING CONDITIONS

May 2004

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TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

A. Overview

The primary objective of this study is to evaluate the VAST transmission system performance for projected 2004 Summer peak load conditions, to identify critical facilities which may limit power transfers between VAST systems, and to develop new operating guides where necessary and possible to improve transfer capabilities.

Diagram 1 shows subregional incremental transfer capabilities to the base case conditions, which includes projected firm transfers. The following is a comparison of the 2004 Summer study to the 2003 Summer study. Comparisons in the Overview are discussed in Section III.B, 'Individual Assessments'.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

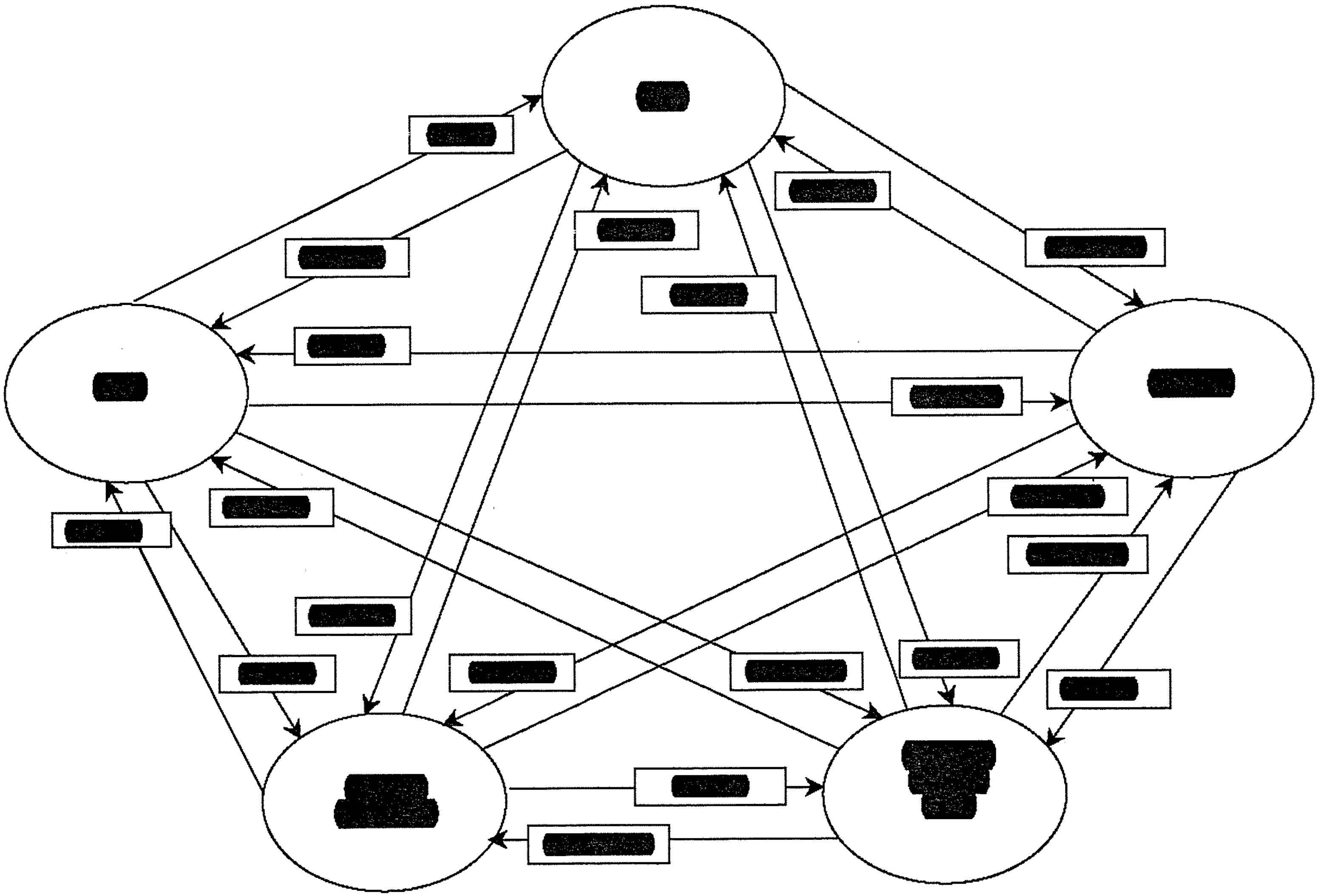
[redacted]

[redacted]

[redacted]

As a part of the transfer capability assessments, an AC power flow was conducted at the transfer test level with the first reported hard limit contingency in effect including any applicable operating guides. No voltage constraints were found for the subregional transfers. This study also includes a base case AC single contingency analysis (ACCC) to test compliance to NERC planning standards I.A.S1 and I.A.S2. A discussion of the results for each participant is located in Section II.

INTERREGIONAL & SUBREGIONAL SUMMARY OF INCREMENTAL TRANSFER CAPABILITIES
2004 SUMMER VAST RELIABILITY STUDY
DIAGRAM 1



(1) Operating Guide Identified

II. INTRODUCTION & STUDY PROCEDURES

A. Introduction

This report documents the results of the VAST 2004 Summer Reliability Study conducted jointly by representatives of CP&L, Duke, SCEG, SCPSA, DVP, AEP, SOCO, GTC, TVA, Entergy, and AECI. This study has for its main purpose the assessment of the reliability of the VAST member transmission systems. The assessment is accomplished by the investigation of: (1) the interconnected system performance during peak load conditions as projected for 2004 summer; (2) the capability of the systems to interchange power in amounts above the base transfers expected for 2004 summer; (3) the effects of various single contingencies on the performance of the individual and combined transmission systems during 2004 summer peak conditions; and (4) the identification of new operating guides where necessary and possible to improve transfer capabilities. The transfer capability values obtained from this evaluation are not used for OASIS posting purposes.

The transfer capabilities determined for this report are non-simultaneous and are based on a computer simulation of the operation of the interconnected electric systems under a specific set of assumed operating conditions. Each simulation represents a single "snapshot" of the operation of the interconnected systems based on the projections of many factors. Among these factors are the expected customer demands, generation dispatch, scheduled maintenance, the configuration of the interconnected systems, and the electric power transfers in effect among the interconnected systems. In the real-time operation of the interconnected electric systems, these factors are continuously changing. As a result, the electric power transfers that can be supported on the transmission systems will vary from one instant to the next. For this reason, the transfer capabilities reported in this study correspond to a specific set of system conditions for the interconnected network and can be significantly different for any other set of system conditions. The transfer capabilities reported in this study should be viewed as indicators of system capability.

Interregional transfer capabilities between the VACAR Subregion and ECAR/MAAC are studied in the VACAR-ECAR-MAAC (VEM) operating studies and are not reported here. In the 2004 MAIN Summer Transmission Assessment Study, interregional transfer capabilities are appraised between the TVA Subregion and MAIN/ECAR within the MAIN-ECAR-TVA (MET) section; between the TVA Subregion and SPP within the MAIN-MAPP-SPP (MMS) section; and between the Entergy Subregion, referred to as "SERC West," and MAIN within the MAIN-SERC West (MSW) section and are not reported here. Interregional transfer capabilities between the Southern Subregion and peninsular Florida are reported in the Joint Florida/SOCO Transfer Capability study.

B. Study Procedure

The VAST base case (VR04S00) is the datum level of these studies. Major generation and transmission facility changes, base case flows on high voltage facilities in the VAST area, and the base case interchange schedule are contained in Section VI, "SUPPORTING DATA," of this report. A comparison of the base case net scheduled interchanges between the 2003 summer study and the 2004 summer study is included in this section as Table 1. The transfer capabilities reported in this study are based on linear power flow studies. AC power flows at the transfer test level were conducted with the first reported "hard limit" contingency in effect for subregional transfers only.

The base case for this study was created from the 2003 MMWG series model of 2004 summer. VAST member utilities supplied and coordinated changes for both member and non-member utility representation. The study results were obtained by using PTI's PSS/E and MUST programs. The base case, linear runs, and AC verifications runs were performed by SOCO; the parallel transfers were conducted by GTC; and the report was assembled by DVP.

The strength of the VAST interconnected network was assessed by determining its ability to support power transfers. The NITCs and FCITCs documented in this study were determined in accordance with the NERC definitions contained in the report: "Transmission Transfer Capability", dated May 1995. These definitions are summarized in Section VI, "SUPPORTING DATA," of this report. For conditions other than those modeled in the VAST base case, response factors which are provided in Section IV, "TRANSFER TABLES," can be used to approximate incremental transfer capability. The TDFs (PTDFs/OTDFs) shown in the tables in the "TDF" column assume the conditions listed.

It should be noted that calculated transfer capabilities in this report were not extrapolated beyond the study test levels. Transfers were simulated by increasing generation in one area and decreasing generation in the other area. However, when necessary, loads were reduced in the CP&L, SCEG, SCPSA, DVP, TVA, Entergy and AECI exporting areas to provide sufficient capacity to model desired levels of transfer. Monitored circuits that are not significantly affected, having less than 3% response to transfers, are not reported here because variations in local conditions would have a more profound effect on these facilities than would studied transfers.

GTC is a transmission owner within SOCO but currently is not a control area itself. As a sensitivity, transfers were evaluated as if GTC was a control area.

AEP is a transmission owner with facilities in the ECAR, SPP, and ERCOT regions. References to AEP in this report are restricted to the AEP Control Area within ECAR.

Table 1 consists of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

III. STUDY RESULTS

Section III.A. consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

B. Individual Assessments

The following discussions center on each company's major transmission and/or operating changes, adequacy of import and export transfer capabilities for the 2004 summer season, and actions that may be required to alleviate overloads on critical facilities based on the results of this study.

Section III.B. consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

IV. TRANSFER TABLES

The following tables provide a summary of Incremental Transfer Capabilities between companies and subregions within the VAST transmission network. These transfer capabilities were calculated using the 2004 summer base model that included firm contracts and native load reservations.

Section IV. Tables A - M consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

V. PARALLEL TRANSFER RESULTS

Section V.A - V.C consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

VI. SUPPORTING DATA

Exhibit A Major Generation and Transmission Facility Changes

Section VI. Exhibits A - G consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

Exhibit I
Abbreviations
2004 Summer VAST Reliability Study

AEC	Alabama Electric Cooperative, Inc.
AECI	Associated Electric Cooperative, Inc.
AEGL	Allegheny Energy Gleason IPP
AEP	American Electric Power-East
AMRN	Ameren
AP	Allegheny Power
BCA	Batesville Control Area
BG&E	Baltimore Gas & Electric
BREC	Big Rivers Electric Corporation
CIL	Central Illinois Light Company
CIN	Cinergy Corporation
CELE	Central Louisiana Electric Company
CLECO	Central Louisiana Electric Company
AEPW	American Electric Power System-West
CP&L	Carolina Power & Light Company
CP&LE	Carolina Power & Light Company East
CP&LW	Carolina Power & Light Company West
CRV	Curtailment Reference Value
CC(s)	Combined Cycle Generator
CT(s)	Combustion Turbine Generator
DEAM	Duke Energy Albany, MS IPP
DEMK	Duke Energy Marshall, KY IPP
DLCO	Dequesne Light Company
DNE	Duke Energy North America
DOE	Department of Energy
DUKE	Duke Energy Control Area
DENA	Duke Energy North America
DENL	Duke Energy North Little Rock
DVP	Dominion Virginia Power
ECAR	East Central Area Reliability Coordination Agreement
EEI	Electric Energy Incorporated
EKPC	East Kentucky Power Cooperative, Inc.
ENTERGY	Entergy Corporation
EST	Entergy, Southern, and TVA
FCITC	First Contingency Incremental Transfer Capability
GRDA	Grand River Dam Authority
GSU	Gulf States Utilities
GTC	Georgia Transmission Corporation
HEC	Hoosier Energy Rural Electric Cooperative
ILLMO	Illinois-Missouri Pool
IP	Illinois Power Company
IPP	Independent Power Producer (also see NUGS)
KCP&L	Kansas City Power & Light Company
LAFA	Lafayette Utility System
LAGN	Louisiana Generating Company
LGEE	LGE Energy
LODF	Line Outage Distribution Factor
LPM	Louisville Power Monroe

Exhibit I
Abbreviations
2004 Summer VAST Reliability Study

MAAC	Mid Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid Continent Area Power Pool
MEAG	Municipal Electric Association of Georgia
MEAN	Municipal Energy Agency of Nebraska
MJMEUC	Missouri Joint Municipal Electric Utility
NCEMPA	North Carolina Eastern Municipal Power Agency
NERC	North American Electric Reliability Council
NI	Northern Illinois (Commonwealth Edison)
NIPS	North Indiana Public Service Company
NITC	Normal Incremental Transfer Capability
NPCC	Northeast Power Coordinating Council
NPPD	Nebraska Public Power District
NRG	NRG Energy, Inc.
NUGS	Non-Utility Generators
NYPA	New York Power Authority
ODEC	Old Dominion Electric Cooperative
OPC	Oglethorpe Power Corporation
OTDF	Outage Transfer Distribution Factor (with facility outage)
OVEC	Ohio Valley Electric Corporation
PEPCO	Potomac Electric Power Company
PEC	Progress Energy Carolinas
PJM	Pennsylvania-Jersey-Maryland Interconnection Association
PTDF	Power Transfer Distribution Factor (without facility outage)
RCP	Reliability Coordination Plan
SCEG	South Carolina Electric & Gas Company
SCEC	South Central Electric Companies
SCPSA	South Carolina Public Service Authority
SCS	Southern Company Services
SEPA	Southeastern Power Administration
SEPCO	Savannah Electric Power Company
SERC	Southeastern Electric Reliability Council
SIGE	Southern Indiana Gas and Electric Company
SIPC	Southern Illinois Power Cooperative
SMEPA	South Mississippi Electric Power Administration
SOCO	Southern Control Area
SOUTHERN	Southern Subregion of SERC
SPRM	City Utilities of Springfield, Missouri
SPP	Southwest Power Pool
SWPA	Southwest Power Administration
TDF	Transfer Distribution Factor
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolina Subregion of SERC
WECC	Western Electricity Coordinating Council (formerly WSCC)
WERE	Western Resources

Exhibit I Transfer Capability Definitions

Exhibit J
Transfer Capability Definitions
2004 Summer VAST Reliability Study

Transfer capabilities as used by the VAST Study Group are defined as follows in accordance with North American Electric Reliability Council (NERC) definitions:

1. Normal Incremental Transfer Capability (NITC)

Installed Incremental Transfer Capability is the amount of power, incremental above normal base power transfers, that can be transferred over the transmission network without giving consideration to the effect of transmission facility outages. All facility loadings are within normal ratings and all voltages are within normal limits.

2. First Contingency Incremental Transfer Capability (FCITC)

First Contingency Incremental Transfer Capability is the amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions.

A. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.

B. The bulk power system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer.

C. After the dynamic power swings following a disturbance resulting in loss of any single generating unit, transmission circuit or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

FINAL PAGE

AMERICAN ELECTRIC POWER
ECAR RELIABILITY REGION

TRANSMISSION PERFORMANCE APPRAISAL OF 2009 PROJECTED CONDITIONS

Prepared For:

Transmission System Performance Panel
East Central Area Reliability Council

Prepared By:
East Bulk Transmission Planning
Transmission Planning Section
American Electric Power Service Corp.

October 29, 2004

AEP AMERICAN ELECTRIC POWER

Foreword

American Electric Power (AEP) performed this Transmission Performance Appraisal at the request of the ECAR Transmission System Performance Panel. Information in this report contains confidential and commercially sensitive information intended only for members of the ECAR Transmission System Performance Panel. If the reader of this message is not the intended recipient or an agent responsible for delivering it to the intended recipient, you are hereby notified that you have received this document in error and that any review, dissemination, distribution, or copying of this message is strictly prohibited.

Questions and comments regarding this document should be referred to:

Scott Lockwood
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EXECUTIVE SUMMARY

The AEP East bulk transmission system is expected to perform as designed in accordance with ECAR and NERC Planning Criteria to provide a reliable delivery system for power to supply AEP's 2009 summer and winter peak loads. The AEP East bulk transmission system is also expected to be a reliable pathway for scheduled power transfers across our system. The following discussion is an overview of the expected performance of the AEP East bulk transmission system for anticipated 2009 conditions. A discussion of AEP's compliance with NERC Planning Standards is included.

The AEP transmission system was assessed assuming forecasted peak load conditions for 2009. The analysis was broken into three AEP East transmission planning regions (Columbus, Fort Wayne, and Roanoke). The analyses of the Columbus and Fort Wayne regions were conducted on the 2009 summer model because these two regions are summer peaking. The analysis of the Roanoke region was conducted on the 2009/10 winter model because this region is winter peaking. In addition, "stressed cases" were developed for each region. These stressed cases consisted of heavy transfers and generation dispatch scenarios to identify AEP's transmission system limits and operating constraints. Thermal and voltage analyses were then performed on the base and stressed cases. A detailed description of the stressed cases, study procedures, and performance criteria is provided later in this report.

Major facility additions in the AEP East area anticipated to be in service prior to 2009 include an upgrade of the [redacted] capacity, the completion of the [redacted] and associated reinforcements, and approximately [redacted] and associated reinforcements.

AEP East is compliant with NERC Planning Standards Category A. With all facilities in-service, the bulk transmission system is expected to remain stable with no potential for loss of load or curtailment of firm transfers. No cascading outages are expected. All facilities are expected to operate within defined voltage limits. Most facilities are expected to operate within normal seasonal ratings except for the following facilities.

[redacted]

None of the above facilities exceed their emergency rating for single contingency conditions. AEP has plans to reinforce the transmission system to eliminate these conditions by 2009.

AEP East is compliant with NERC Planning Standards Category B. With an outage of any single bulk system element (generator, circuit, or transformer), all EHV (230-765 kV) facilities are expected to operate within normal seasonal ratings and all HV transmission (100-161 kV) facilities are expected to operate within emergency seasonal ratings. All facilities are expected to operate within defined voltage limits. AEP's bulk transmission system is expected to remain stable with no potential for loss of load or curtailment of firm transfers. No cascading outages are expected.

AEP is compliant with NERC Planning Standards Criteria C except for the [redacted] area. Voltages at the [redacted] station are below acceptable levels during [redacted] conditions. This is a notable change in voltage performance from comparable 2004 conditions. AEP is conducting further analyses of the anticipated voltage performance in this area. Two other areas of voltage concern were identified. However, the voltage concerns in these two areas will be mitigated with currently planned transmission reinforcements or established operating procedures.

In addition, potential thermal overloads were identified for a few facilities during [redacted] In each case, AEP plans to reinforce the transmission system to eliminate these overloads.

AEP conducted Category C cascading events analysis. No event resulted in a cascading outage condition based on ECAR/NERC criteria. AEP also conducted tests under conditions exceeding ECAR/NERC criteria that showed the possibility for cascading outages and voltage collapse. The double contingency event of the [redacted] circuits during peak loads and transfer levels at 105% of FCITC (exceeding NERC criteria) will result in loading above [redacted] The limiting facility is the [redacted] circuit. Curtailment of [redacted] generation at the [redacted] Station (as permitted by the Interconnection Agreement) and at AEP's [redacted] Plant will be sufficient to mitigate loading concerns. There are several other scenarios where transmission facilities could be loaded above 100% of their emergency rating under peak load, transfers at 105% of FCITC, and double contingency conditions. If the overloaded facility were to trip, a cascading outage is possible.

AEP examined the potential for cascading events under NERC Category D analyses. None of the scenarios that were examined resulted in overloads above 130% (ECAR's performance criteria). However, scenarios were identified where tripping of [redacted] In all cases, these conditions were at forecasted peak load and transfers at 105% of FCITC. AEP will continue to examine the severity and potential risk of these scenarios.

Details of these and other analyses can be found in the complete report.

INTRODUCTION

This report provides an assessment of the American Electric Power (AEP) East transmission system for the 2009 summer and winter period. AEP owns and operates transmission systems in ECAR, SPP, and ERCOT. This assessment study is limited to bulk transmission facilities within ECAR. The report is presented to the ECAR Transmission System Performance Panel (TSPP), and meets the requirements for future year transmission system assessments established by the TSPP. These requirements are detailed in the ECAR Peer Review Checklist along with references to the applicable sections of this report.

Summarized are results of load flow and voltage stability analyses performed by AEP's Transmission Planning Section. The analyses were divided into 3 transmission planning regions (Ft. Wayne, Columbus, and Roanoke) and were performed by engineers who are experienced with the design and operation of their respective regions.

The focus of the analyses is to identify potential operating constraints for all facilities on the AEP East system rated [redacted] and above and to measure compliance with NERC Planning Standards. **AEP performed these analyses using more severe assumptions than stipulated in the NERC/ECAR criteria.** However, decisions to reinforce the bulk transmission system include an assessment of the performance as compared to AEP, ECAR, and NERC criteria.

The first step is to establish FCITC values for a multitude of directions. For each direction, a stressed case is created modeling peak load and transfers at the FCITC limit with which contingencies defined in the NERC Planning Standards -- Categories A, B, C, and D of Table 1 -- are simulated to identify potential thermal, voltage, or stability constraints. **This exceeds NERC/ECAR criteria**, which only require transfers modeled for projected firm (non-recallable reserved) transmission services. Variations of these stressed cases are also created to study situations special to certain geographic areas, such as [redacted] during shoulder peak load periods, variations in generation dispatch patterns, or extraordinary load and power factor levels. These variations are developed based on the experiences of the engineers and history of situations experienced by AEP in the past. A more detailed explanation of the stressed cases is provided within the report.

The base case utilizes a detailed model of the AEP system that includes the transmission and subtransmission network. The inclusion of the subtransmission network allows more accurate representation of power flows and voltages that could be affected by transformer tap changes and switched reactive devices on the subtransmission system as conditions change. The models of the transmission systems connected to AEP were taken from the 2003 Series NERC MMWG Base Cases. Transmission models of systems remote from AEP were reduced to equivalent representations.

The AEP bulk (EHV) transmission system includes all facilities rated [redacted] and above. The high voltage (HV) transmission system includes all facilities rated between [redacted] and [redacted] The subtransmission system includes all facilities rated below [redacted] This assessment monitored all facilities [redacted] and above.

Transmission reinforcements and operating procedures are reviewed with AEP system operators as plans and procedures are finalized.

Although a variety of system conditions were reviewed, it is noted that actual day-to-day power flows of the transmission system may vary significantly from the conditions modeled. Also, models developed by other ECAR transmission owners may differ from those used in this study. The results provided are not intended for use as absolute capability but to identify potential limitations and provide an early indicator of potential system reinforcement requirements.

ABOUT AEP

AEP owns and operates more than 36,000 MW of generating capacity in the United States. It is the largest electricity generator in the U.S. AEP is also one of the largest electric utilities in the U.S. with more than 5 million customers linked to AEP's electric transmission and distribution grid.

In ECAR, AEP has more than 22,000 circuit miles of transmission lines, more than 675 transmission stations, and about 150 transmission interconnections with neighboring transmission systems. AEP's transmission system in ECAR traverses 7 states. AEP's transmission system operates at 765 kV, 500 kV, 345 kV, 230 kV, 161 kV and 138 kV voltage levels. It is an integral part of the Eastern Interconnected Network and is highly responsive to changing conditions on the Network.

TRANSMISSION PLANNING ORGANIZATION

This transmission performance appraisal of the AEP transmission network is conducted by the Transmission Planning Section of AEP, primarily by engineers in the East Bulk Transmission Planning (EBTP) group. The EBTP group has been conducting seasonal peak load performance appraisals and long range planning appraisals for over 25 years. In addition, the Transmission Planning Section has a close working relationship with the Transmission Operations personnel within AEP.

The East Bulk Transmission Planning group is responsible for developing plans to maintain the reliability of the EHV transmission system within AEP, including voltage levels from 765 kV down thru 230 kV. The performance of the 138 kV network is also evaluated as related to the significant impact the EHV network can have on the 138 kV transmission network.

The long history and extensive experience in the planning and operating of the AEP transmission network is reflected in the determination of stressed cases and selection of contingencies under study for this appraisal.

LOAD FLOW ANALYSIS

BASE MODEL DEVELOPMENT

The 2003 series NERC MMWG 2010 summer and 2010 winter base case load flow models served as the foundations for building of the load flow model used in this appraisal. The AEP transmission system in the NERC MMWG models was replaced with a detailed 2009 summer and 2009 winter model, respectively, of the AEP transmission and subtransmission networks. The AEP distribution network is modeled as the equivalent fixed PQ load as seen by the transmission and subtransmission step-down distribution transformers.

The AEP generation is economically dispatched to meet its load and interchange requirements. The base model includes only those interchange transactions for which there are firm transmission reservations with energy contracts in place to utilize the reservation. In some cases, the interchange transactions include expected transactions required for load supply.

Merchant power plants are generally dispatched only if firm reservations and points of receipt are established or for load supply requirements. Merchant power plants are used for establishing stressed cases in this appraisal.

FACILITY ADDITIONS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

PERFORMANCE STANDARDS

Performance standards provide the basis for determining whether system response to the contingency tests is acceptable. Depending on the nature of the study, one or more of the following types of performance standards will be applied: thermal, voltage, relay, steady-state stability, and transient stability.

In general, system response to contingencies evolves over a period of several seconds or more. Steady state conditions can be simulated using a load flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency load flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance. For the eastern AEP System, thermal and voltage performance standards are usually the most constraining measures of reliable system performance. Each type of performance standard is described in the following discussion.

Performance Standards - Thermal Limits

Thermal ratings define transmission facility loading limits. Normal ratings are generally based upon no loss of facility life or equipment damage over a 24 hour period.

Emergency ratings accept some loss of life or strength over a 24 hour period, typically, however some ratings are defined for a shorter time period. The thermal rating for a transmission line is defined by the most limiting element, be it a conductor capability, sag clearance, or terminal equipment rating. When a line is terminated with multiple circuit breakers, as in a ring bus or "breaker and a half" configuration, it is assumed that the line flow splits equally through the terminal equipment unless one breaker is open. Ratings in load flow simulations normally assume all breakers are in service.

Thermal ratings for major transmission equipment are normally the most limiting transmission constraints. Other ancillary equipment, such as metering CTs and relays, also have thermal limits but these limitations are not generally treated as restrictions to system operation because such equipment can usually be replaced as needed at modest cost. However, these overloads are noted so that appropriate steps may be taken. In addition, during extreme conditions testing, it is essential to determine whether relay or circuit breaker failure or misoperation will result in cascading outages and/or power interruptions.

Normal ratings are applied for base and transfer conditions without outages. Emergency ratings are used to assess performance following single contingencies but before any applicable operating procedures are implemented. Following an outage, system operators will implement available operating procedures to reduce all facility loadings to within levels to avoid exceeding emergency ratings should the next contingency occur. The application of these facility loading limits is summarized in Table 1. Where the ability to operate at loading levels up to emergency ratings is critical to acceptable system performance, the emergency ratings are verified. This is particularly important in the case of transmission lines, which may be limited by sag clearances.

Most thermal ratings are defined in amperes. However, transmission planning studies use ratings expressed in MVA, based on the ampere rating at nominal voltage. When voltages during testing deviate considerably from nominal, the MVA rating is adjusted for the voltage deviation from nominal.

Table 1 AEP Transmission Planning Criteria (Steady State System Performance)			
		Minimum Bus Voltage	
Transmission System Condition	Maximum Facility Loading (Rating)	EHV	138 kV
All facilities in service	Normal	95%	95%
One facility out of service	Emergency (1) Normal (2) Emergency (3)	90%	92%
Two facilities out of service	Emergency	90%	92%
(1) Operational planning criteria before operating procedure implemented. (2) Facility planning criteria (EHV facilities). (3) Facility planning criteria (138 kV facilities).			

Performance Standards – Voltage Limits

Voltages at transmission stations should be above the values listed in Table 1 to reduce the risk of system collapse and/or equipment problems. In addition, voltages at generating stations below minimum acceptable levels established for each station must be avoided to prevent tripping of the generating units. High voltage limits are specific to particular pieces of equipment, but are typically 105% of nominal.

Performance Standards – Relay Trip Limits

Relay trip settings, selected primarily for fault conditions, could be reached in some cases during contingency loading conditions or transient power swings. These relay trip settings are evaluated in operational planning studies to determine whether adjustments are needed. If it is not practical to revise the setting, subsequent planning studies must recognize that the line could trip due to the resultant contingency loading condition.

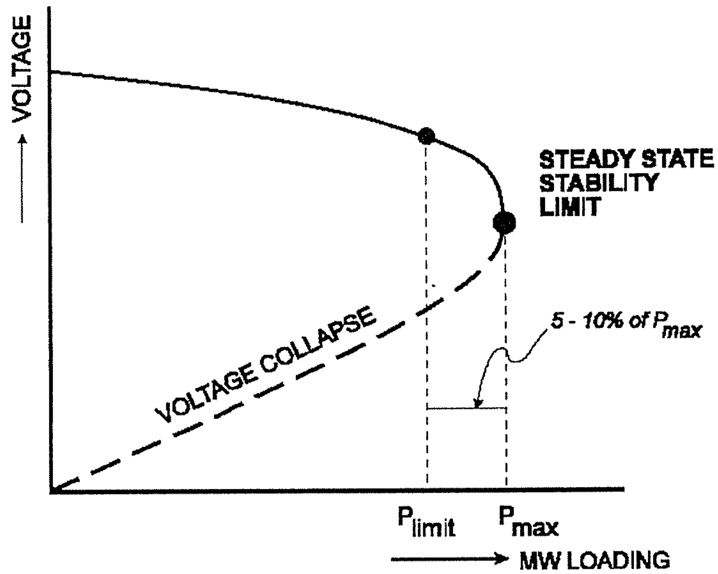

Figure 1

Performance Standards - Steady-State Stability Limits

The steady-state stability limit (P_{MAX} in Figure 1) is the point at which no more power can flow through a system without precipitating a voltage collapse. This limit is often related to heavily loaded systems where even small perturbations, such as the normal adjustment of generator output to match load, could cause system collapse. Steady-state stability limits are typically evaluated using power vs. voltage (PV) curves or power vs. angle curves, for individual lines or transmission interfaces. In planning studies, a loadability limit is defined, which includes a safety margin of 5-10% below the theoretical maximum power flow.

Performance Standards – Transient Stability Limits

Transient stability refers to a power system's ability to remain in synchronism following a disturbance, such as a short circuit. Facilities must be planned and operated so that all generating units remain stable through the transient period regardless of the plant's output level prior to the disturbance. Also, transient voltage dips at generating stations below established minimum acceptable levels, and for significant durations, must be avoided to prevent tripping of the auxiliary loads, which in turn, could trip generating units.

Oscillatory stability refers to a power system's ability to damp out electromechanical oscillations (or power swings) in the 0.1-3.0 Hz range. Oscillatory modes within this range inherently exist on any power system. Oscillatory instability is manifested in terms of sustained or growing oscillations in various electrical quantities observable at power plants and on the transmission system, following a disturbance, or a routine network operation such as load ramping. These oscillations must be suppressed within seconds to prevent potential equipment tripping and damage. The oscillatory instability limit is defined as the power level beyond which one or more generators or groups of generators continue to exhibit one or more sustained modes of oscillation beyond a reasonable time limit. Generally, this limit is not dependent on the size of the disturbance or the period of the mode. Any sustained or growing oscillation that persists beyond a reasonable time period indicates that the stability limit has been exceeded and represents unacceptable performance.

STUDY AREAS

The AEP transmission system and load areas are broken into three major study areas. The areas are identified as the Roanoke, Columbus, and Ft. Wayne transmission planning areas. These areas are defined in Figures 2 and 3 according to load centers and transmission, respectively.

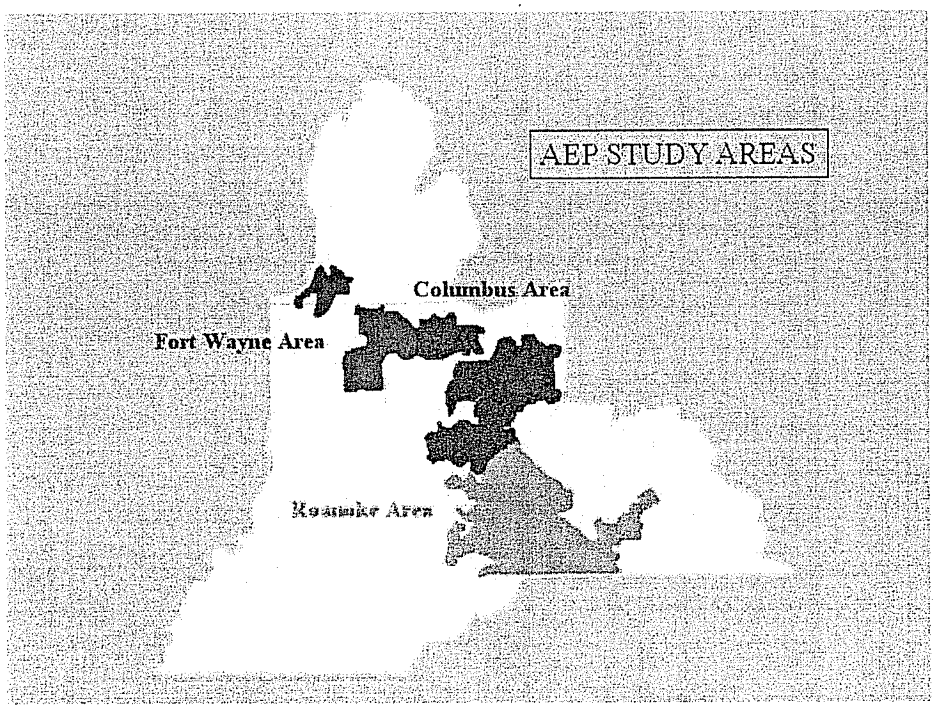

Figure 2

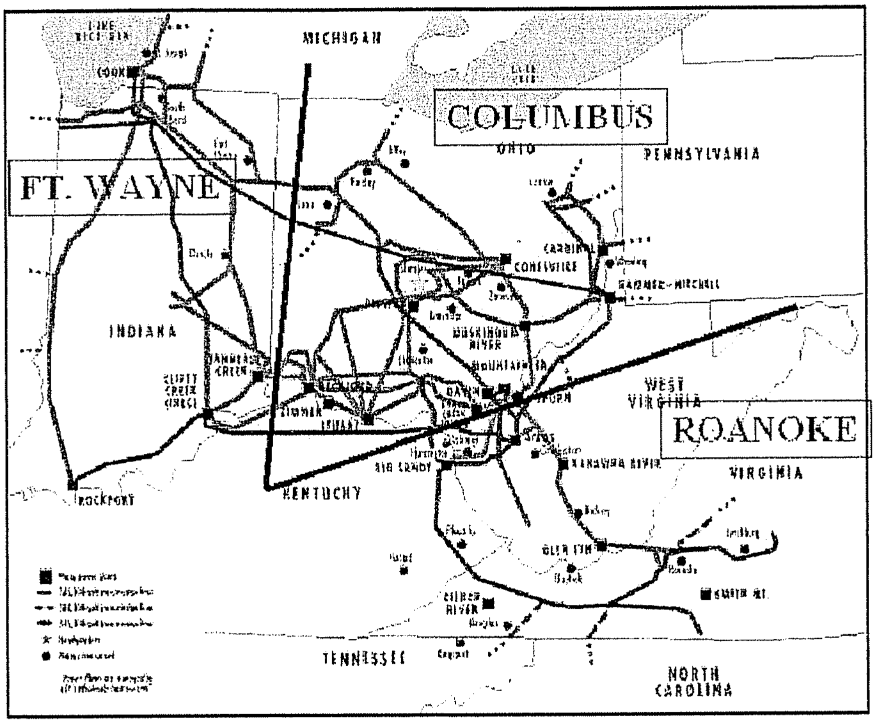

Figure 3

STRESSED LOAD FLOW MODELS

A set of stressed cases upon which to apply contingencies was established for each study area. The stressed cases include situations involving combinations of transfers at calculated FCITC levels, changes in load level, and changes in generation dispatch. Transfer directions are indicated in relation to the study area. Each study area assessment has included only the stressed cases that have significant results. Stressed cases for other conditions may have been reviewed but are not included in this report. The following details the stressed cases included in this report.

Columbus Study Area

[redacted]

Ft. Wayne Study Area

[redacted]

Roanoke Study Area

[redacted]

CONTINGENCY ANALYSIS

Load flow contingency analyses were performed on the base case and on the stressed cases. Contingencies included facilities within AEP and in neighboring control areas. Global contingency screening was conducted for NERC Categories A and B. NERC Category C was analyzed using contingencies from Types 1-5 and Type 10 of the ECAR Linear Load Flow Database. NERC Category D was analyzed using contingencies from Types 6-9 of the ECAR Linear Load Flow Database.

LOAD FLOW ANALYSIS RESULTS

The following sections of this report provide the results of the FCITC Analysis, a listing of Key Facilities, PV Curve Analysis, NERC Category A, B, and C Analyses, and Cascading Events Analysis. The FCITC analyses were conducted on the base case to establish transfer limitations. The stressed cases are transfer cases established at the FCITC levels. Testing on the stressed cases is more severe than NERC Criteria requirements. NERC Criteria requirements call for transfers at projected firm transmission service levels, which are represented by the transfers included in the base case.

The Key Facilities tables show the potential thermal or relay limited overloads that may occur for N-0, single, double, and multiple contingency conditions at the FCITC levels. The PV Curve Analyses included in each sub-area appraisal show the potential for low voltage conditions during transfer and contingency conditions. The NERC Category A, B, and C Analyses discusses AEP's adherence to the performance criteria. The Cascading Events Analysis looks at the potential for transmission or generation facilities to trip initiating a cascading outage situation and eventual area collapse.

FCITC ANALYSIS

Page(s) 18 - 20 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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KEY FACILITIES

Page(s) 22 - 24 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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PV CURVES

Page(s) 26 - 31 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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NERC
CRITERIA
ANALYSIS

(CATEGORY A, B, C, and D)

Page(s) 33 - 45 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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OPERATING PROCEDURES

This subsection lists and briefly describes various operating procedures that have been developed to enhance the performance in specific areas of the bulk power system. The procedures described herein, all of which result in changes in network configuration or generation dispatch levels, generally are implemented to achieve one or more of the following goals:

- To reduce facility loadings to within equipment thermal capabilities;
- To maintain acceptable transient stability margins at generating stations;
- To improve area reliability without exceeding the short circuit capabilities of circuit breakers;
- To insure adequate voltage levels or steady state stability margins are maintained.

The following listing of operating procedures is separated by AEP's Transmission Planning Regions.

Page(s) 47 - 59 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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ECAR Peer Review Checklist

ECAR Peer Review Checklist

ECAR REVIEW PROCESS FOR EVALUATING MEMBER SYSTEMS FUTURE YEAR TRANSMISSION ASSESSMENTS

CHECKLIST TO DETERMINE VALID ASSESSMENT

REQUIRED ITEMS	AEP REPORT
1. Selected base case stated in assessment [2008, 2009, or 2010, and either summer or winter].	Base Model Development, page 9
2. Sub-area(s) defined or rationale for not selecting sub-area(s) provided.	Study Areas, page 15
3. Global single contingency testing performed against **base** case for area and sub-area(s).	NERC Category B Analysis, page 34
4. Global double contingency testing of bulk facilities performed against **base** case for area and sub-area(s).	Contingencies selected from ECAR linear load flow contingencies.
5. NERC Category C contingency testing, in addition to global double contingencies, performed against **base** case for area and sub-area(s).	NERC Category C Analysis, page 35
6. NERC Category D contingency testing performed against **base** case for area and sub area(s).	NERC Category D Analysis, page 40
7. Analysis performed on affect of failure of operating procedure or Special Protection Systems that could critically impact ECAR bulk electric system, or a statement that none were identified.	Special Protection Systems, page 44
8. Voltage collapse analysis performed.	NERC Category C Analysis, page 35 NERC Category D Analysis, page 40
9. PV-curves included in report with comparison of results against most recent ECAR summer (winter) seasonal assessment.	PV Curves, page25 NERC Category C Analysis, page 35
10. Discussion on stability performance criteria and whether or not each of member's generating plants adhere to those criteria.	Stability Analysis, page 44
11. List showing thermal or voltage violations of all non-cascading NERC Category B events along with their values and conditions (case description, contingency, rating, percent rating or percent voltage, and identification of rating such as summer 24 hour emergency, etc.) for base case conditions. Also, proposed mitigation plans including descriptions of any operating procedures and schedule of any proposed facilities for all NERC Category B violations under base case conditions.	NERC Category B Analysis, page 34
12. List showing thermal or voltage violations of all non-cascading NERC Category C events along with their values and conditions (case description, contingency, rating, percent rating or percent voltage, and identification of rating	NERC Category C Analysis, page 35

such as summer 24 hour emergency, etc.) for base case conditions.	
13. Discussion of any potential cascading events (NERC Category B, C and/or D events) included in report or a statement that none were identified. Must also include discussion of facilities monitored in neighboring systems.	NERC Category B Analysis, page 34 NERC Category C Analysis, page 35 NERC Category D Analysis, page 40
14. Executive summary included in report.	Executive Report, page 4
15. Brief description of member's thermal and voltage criteria used in member's assessment included in report. Member's stability criteria also included in report.	Performance Standards, page 10
16. Description of base case including key assumptions such as generation dispatch and controllable devices, included in report.	Base Model Development, page 9
17. Listing of new bulk electric system facilities or other significant lower voltage facilities included in the model that were not in the most recent ECAR summer (winter) assessment model, or a statement that there are no additional facilities.	Facility Additions, page 9
18. Description of facilities considered part of bulk electric system included in report. An example would be "all facilities rated 230 kV and above".	Introduction, page 6
19. Statement that all facilities on member's system rated 100 kV and above were monitored in the assessment, included in report.	Introduction, page 6
20. List of contingencies other than global singles and global doubles, included in report.	Contingency Analysis, page 16
21. Statement on whether contingencies on neighboring systems were considered, and to what extent they were considered, included in report.	Contingency Analysis, page 16
22. Statement that operator input was obtained on any proposed solutions to violations or on any operating procedures.	Introduction, page 6

SYSTEM PERFORMANCE ANALYSIS REPORT

Prepared by the
East Bulk Transmission Planning Section
of the Transmission Planning Department

TABLE OF CONTENTS

Rev. 5/04

SYSTEM ANALYSIS REPORT

Initial Issue	6/1/97

Revisions

1. Added pages for Winter 1997/98 review	12/97
2. Added pages for Summer 1998 review	06/98
3. Added pages for Winter 1998/99 review	12/98
4. Added pages for Summer 1999 review	05/99
5. Added pages for Winter 1999/00 review	12/99
6. Added pages for Summer 2000 review	05/00
7. Added pages for Winter 2000/01 review	12/00
8. Added pages for Summer 2001 review	05/01
9. Added pages for Winter 2001/02 review	11/01
10. Added pages for Summer 2002 review	05/02
11. Added pages for Winter 2002/03 review	12/02
12. Added pages for Summer 2003 review	05/03
13. Added pages for Winter 2003/04 review	12/03
14. Added pages for Summer 2004 review	05/04

LAYOUT OF REPORT

This report has main sections and subsections. The report will be maintained as a current document through periodic updating of selected pages. This will generally include material related to system performance and the modeling used in load flow cases. Data that is normally unchanged (e.g., tap data and generator capabilities) is included in an Appendix.

First, there is a section of summaries of system performance. There is an executive summary for all of eastern AEP, followed by more detailed summaries for each of the operations offices – Ft. Wayne, Columbus and Roanoke.

Next, there is a section which details some aspects of the data used in load flow models for projected peak conditions, including projected loads, projected power transfers, and transcriptions of a no-contingency load flow cases (for both projected peak load and an extreme weather peak load).

Then, there is a major section that details the expected performance in upcoming load periods. The section consists of Key Facility tables that identify the transmission facilities that are potential overload or voltage problems. The tables are listed by the limiting facility for each of the three areas. The rating and limiting equipment are identified. Transmission outages, generation changes, and transfers that can have a significant impact on the limiting facility are also provided along with the respective response factors. The expected percent overload of the critical facility for the stressed conditions, which include the listed contingencies and transfers, is provided. Details of the listed transfers are provided in each section behind the Key Facility tables.

The final section is an Appendix. It contains relatively stable data, including: circuit ratings (for summer and winter), transformer tap data, generating unit capability data, a list of abbreviations, and a description of operating procedures across the system.

EXECUTIVE SUMMARY
2004 SUMMER – BULK TRANSMISSION APPRAISAL

The AEP East bulk transmission system is expected to perform as designed in accordance with ECAR and NERC Planning and Operating Criteria to provide a reliable delivery system for power to supply AEP's 2004 summer peak load. The AEP East bulk transmission system is also able to function as a reliable pathway for scheduled power transfers across our system. The following discussion is an overview of the expected performance of the AEP East bulk transmission system for Summer 2004. Detailed summaries of performance are provided in subsequent pages for each of the AEP East Transmission Regions (Columbus, Fort Wayne, and Roanoke).

The AEP transmission system was assessed for both forecasted peak load and extreme weather (106% of forecasted load) modeled conditions for summer 2004. In addition, "stressed cases" were developed for each sub-area identified as the three AEP East transmission regions (Columbus, Fort Wayne, and Roanoke). These stressed cases, described in more detail in the Performance Analysis section of this report, consisted of heavy transfers and generation dispatch scenarios to identify AEP's transmission system limits and operating constraints. Thermal and voltage analyses were then performed on the base and stressed cases.

Some areas of the Roanoke and Columbus Transmission Regions could experience loadings approaching thermal limitations. Areas of voltage depression could also occur if critical multiple contingencies occur during periods of heavy loading and forecasted power transfers. Approval of transmission service requests will need to be limited. Transmission Loading Relief (TLR) procedure will be implemented to control power flows on critical circuits to maintain adequate reliability on the AEP transmission system.

The AEP East bulk transmission system remains relatively unchanged as compared with system configuration in 2003 summer. In comparison to projected conditions for Summer 2003, the following differences are expected for Summer 2004 conditions:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]

6. [redacted]

7. [redacted]

One of the two most critical areas of concern continues to be in the [redacted] of the Roanoke Transmission Region. Combinations of [redacted] in conjunction with [redacted] could result in a voltage collapse condition absent proactive operator intervention. Close monitoring in the Roanoke Transmission Region must and will be maintained.

The [redacted] circuit could reach its voltage limit set by the [redacted] guidelines with minimal transfers to the [redacted] in conjunction with double contingencies. It is the limiting EHV facility for transfers to the [redacted] Single contingencies that may result in flows approaching limitations of the [redacted] circuit are [redacted] and [redacted] circuits.

In addition, [redacted] the [redacted] and [redacted] transformers, the [redacted] the [redacted] and [redacted] transformers, and several [redacted] lines can overload during heavy transfers concurrent with double contingencies.

The other area of concern is the thermal capability of the [redacted] transformer in the Columbus Transmission Region. A marginal increase in thermal capability was anticipated for this summer with the addition of a new [redacted] transformer. Due to a failure during manufacturer testing, the transformer will not be delivered on site before the beginning of summer. Therefore, the thermal rating of this transformer will be the same as in summer 2003. Heavy flows on this transformer are anticipated, based on the history of power flows over the past several years. Two new [redacted] single phase transformers are currently being manufactured and are to be delivered by the end of 2004 to replace the current [redacted] single phase transformers in the heaviest loaded phases, which will increase the capability of this bank, by approximately [redacted] prior to summer 2005.

Under heavy loading and severe transfer conditions the following Columbus Transmission Region EHV facilities could also see loading approaching their emergency capabilities under [redacted] conditions:

[redacted]

The performance of the Ft. Wayne Transmission Region is expected to be similar to last summer. Analysis for 2004 summer indicates that transfers to the [redacted] across this region will be the most limiting. Similar to last summer, the [redacted] transformer is subject to overloads. Transfers to the [redacted] and [redacted] increase power flows through the transformer, but it does not respond more than 3%. Configuration changes on the [redacted] network can mitigate power flows through the transformer.

The [redacted] circuit is being operated normally open to keep fault levels at the [redacted] station within acceptable levels. The [redacted] breakers were scheduled to be upgraded with the addition of the [redacted] which has been cancelled.

Double contingencies concurrent with heavy transfers are required to cause any overloads in the Fort Wayne Transmission Region. Under these conditions, the [redacted] transformers and the [redacted] tie lines along with several [redacted] circuits can overload.

In general, voltage performance is expected to be acceptable on the AEP East bulk transmission system for summer 2004. Various severe scenarios were studied to identify possible voltage depression that could lead to a cascading event or system collapse. These results are detailed later in the report.

For identified conditions, operating procedures and TLRs will be implemented as appropriate to ensure the continued reliable operation of the transmission system. Details of the sub-area appraisals can be found in the individual Columbus, Fort Wayne, and Roanoke Transmission Region Appraisals included in this report.

FORT WAYNE TRANSMISSION REGION
2004 SUMMER -- BULK TRANSMISSION SYSTEM ANALYSIS

By Chris Shaffer

SUMMARY

System performance for summer 2004 in the Fort Wayne Transmission region is expected to be similar to the 2003 summer performance. Analysis for the 2004 summer indicates that transfers to the [redacted] as well as, transfers from the [redacted] across the Fort Wayne Transmission Region, are the most limiting. Forecasted conditions for the 2004 summer include a total sub-transmission load of [redacted] and [redacted] for the Indiana and Michigan (I&M) service area, which is a slight increase from the forecasted I&M sub-transmission load for the 2003 summer. Several system configuration changes have occurred since the 2003 summer and are listed below:

- The [redacted] and [redacted] circuits were upgraded in 2003 to increase the capacity of the interconnections up to the conductor rating, [redacted] However, unresolved sag limits on these [redacted] limited capabilities to the conductor normal ratings of these facilities. A sag study was completed and results from the study indicated that several clearance violations needed to be corrected to operate the line at its maximum operating capability. Efforts are underway to correct the sag limitations prior to the 2004 summer. However, the normal conductor rating was used in this study to determine if any problems would occur on this line should the sag limitations not be removed prior to the summer.

- The net overexcited reactive capability of [redacted] was reduced from [redacted] due to a low H2 pressure operating limit. Study results indicate that the reduction in reactive capability will not degrade the voltage performance of the South Bend service area.

- A new [redacted] interconnection was established with [redacted] station, which was cut into the [redacted] line. As part of this project, the [redacted] line was reconductored with 556 ACSR conductor. Bus and riser upgrades at [redacted] were included as part of this project.

- One additional [redacted] became operational in the Fort Wayne Transmission Region since the 2003 summer.

  [redacted] This [redacted] is connected to the [redacted] station and has a maximum summer operating capability of [redacted] No additional EHV thermal limitations in the Fort Wayne Transmission Region are expected this summer with this facility in service.

Other [redacted] that were available for operation last summer, which could impact performance of the Fort Wayne Transmission Region this summer include:

[redacted]

- The [redacted] circuit is being operated normally open, via supervisory control at [redacted] to keep fault levels at [redacted] within acceptable levels; however, circuit breakers [redacted] and [redacted] at [redacted] could still exceed their maximum operating capability under this operating scenario. Therefore, circuit breakers [redacted] and [redacted] are also to be opened when personnel enter [redacted] Station. New [redacted] circuit breakers are scheduled for installation at [redacted] with construction to begin in the fall of 2004 and to be completed prior to the 2005 summer.

- The [redacted] is the only [redacted] expected to be operational on the [redacted] this summer. The remaining three [redacted] are not expected to operate during the 2004 summer.

Thermal limitations in the Fort Wayne Transmission Region include traditional constraints as well as some new areas of concern. Similar to last summer, the [redacted] transformer is subject to overloads. Transfers to the [redacted] and [redacted] increase power flows through the transformer, but it does not respond more than 3%. Configuration changes on the [redacted] network can mitigate power flows through the transformer. The most critical thermal limitations for the 2004 summer occur at the following facilities:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The voltage performance of the Fort Wayne Transmission System is expected to be adequate for the 2004 summer operating period. The South Bend service area is not expected to have any voltage problems under heavy transfer scenarios and double outage conditions. The Fort Wayne/Marion/Muncie service areas could experience low voltages under severe conditions, which include [redacted] Facilities in western and southern Indiana could see potential low voltages concurrent with [redacted] scenarios and [redacted] Most of the voltage problems arise with outages in combination of an outage of the [redacted] line. Following the [redacted] Operating Guidelines will help reduce the voltage concerns under these severe conditions.

The remainder of this report focuses on discussing the system responses to these credible outages, in conjunction with variable load levels and transfers. Actions to alleviate the adverse conditions caused by the outages are also discussed. Additional information on these contingency scenarios can be found in the detailed Performance Analysis section of this report.

SYSTEM MODELING AND ANALYSIS

Peak load and extreme weather (106% of peak load) models were constructed for the 2004 summer using best available data from internal and external sources regarding load, generation, and interchange. "Stressed" cases were created by adding transfers at the reported FCITC level for use in AC thermal and voltage analysis. DC and AC load flow analysis was performed on the peak load model as well as the stressed transfer cases. Transcription diagrams of the transfer cases are provided in the Key Performance section of this report.

TRANSFER CAPABILITY

First Contingency Incremental Transfer Capabilities (FCITC) were determined for transfer biases in several directions across the Fort Wayne Transmission System. The FCITC values were calculated based on a [redacted] The FCITC values listed below are for those transfer scenarios that were determined to be the most credible and have the most impact on the Fort Wayne Transmission System.

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

THERMAL PERFORMANCE – SOUTH BEND AREA

On 05/07/04 the [redacted] transformer failed and was determined to be irreparable. The analysis contained in this appraisal was conducted prior to this transformer failure, however the impact of this event and the courses of action to remedy this scenario are noted below.

Transfer capability in the Fort Wayne Transmission Region is not impacted with the [redacted] out of service due to facilities in the area having a low response to transfers. The outage of the [redacted] increases the loading on the surrounding area [redacted] especially the [redacted] With all facilities in service, no problems are expected on facilities in the South Bend service area. However, single contingency reliability in the South Bend service area is jeopardized as a result of the [redacted] outage. A [redacted] from [redacted] will be moved to [redacted] and is currently expected to be fully functional by the first week of July 2004. The [redacted] has approximately the same rating as the [redacted] but has a lower impedance which will slightly increase the [redacted] through [redacted] as compared to past load levels.

The [redacted] could exceed its summer normal rating this summer with all facilities in service and heavy transfers to the [redacted] The [redacted] may also exceed its emergency rating under many scenarios for [redacted] as well as, for [redacted]

- [redacted]
- [redacted]

Many double contingency scenarios may also cause the [redacted] to exceed it's emergency rating this summer. [redacted] involving either the [redacted] or the [redacted] have the greatest impact on the loading of this facility. [redacted]

[redacted]

The [redacted] is not highly responsive to local area generation, however an outage of [redacted] could increase the loading on [redacted] by over six percent.

To mitigate the loading on the [redacted] open the [redacted] line. Further loading reductions on the [redacted] may be accomplished by opening the [redacted] section.

To help alleviate the loading concerns on this facility, the current [redacted] is scheduled to be replaced with a [redacted] This upgrade will also reduce the loading on the [redacted]

The [redacted] may exceed its summer emergency rating concurrent with peak load conditions, double contingency scenarios, and heavy transfers to the [redacted] The following double outage scenarios resulted in the greatest contingency loading of [redacted]

[redacted]

[redacted]

[redacted]

With this facility's high response to transfers, TLR procedures may have to be implemented to mitigate overloads on the [redacted]

The [redacted] may also experience heavy loading, concurrent with peak load conditions, double contingency scenarios, and heavy transfers to the [redacted] however, the emergency rating of this [redacted] should not be exceeded unless loads increase beyond forecasted levels or transfers to the [redacted] are exceedingly high. The [redacted] has approximately [redacted] more capability than the [redacted] and is more adept at withstanding heavy transfers to the [redacted]

- [redacted]

[redacted]

- [redacted]

[redacted]

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COLUMBUS OPERATIONS CENTER
2004 SUMMER – BULK TRANSMISSION APPRAISAL

By Bart Taberner

SUMMARY

System performance for summer 2004 in the Columbus Transmission Region is expected to be typical as compared to conditions experienced the last few years. System performance will once again be tied closely with load levels and power transfers across the AEP system. Analysis for summer 2004 shows that transfers biased to the [redacted] and [redacted] are again the most limited. The Columbus Transmission Region has experienced very little change in system configuration since summer 2003. The primary area of concern for summer 2004 is the thermal capability of the [redacted] A marginal increase in thermal capability was planned for [redacted] with the addition of a new [redacted] Due to a failure during testing, the [redacted] will not arrive in time to be utilized for this summer, so thermal ratings for [redacted] are basically unchanged from summer 2003. [redacted] has become limiting in certain situations due to the failure of [redacted] However, operating procedures are in place to mitigate the overload. The availability of [redacted] for the first time in a few years will generally have a positive impact on system conditions in the Columbus and Lima areas. [redacted]

[redacted]

The total subtransmission load for Ohio Power is forecasted to be 1.0% lower for summer 2004 than the forecast in 2003. The total subtransmission load for Columbus Southern Power is forecasted to be 5.6% higher than summer 2003.

Voltage performance should be similar or slightly improved for the Columbus metropolitan area for summer 2004 as compared to summer 2003. For most expected conditions under peak loads, voltage performance should be acceptable. The availability of [redacted] this summer may be a factor in the slightly improved voltage levels. [redacted] also mitigate voltage performance concerns as generation levels increase. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

SYSTEM MODELING

Peak load and severe weather (106% of peak load) system models were constructed for summer 2004 using best available data from internal and external sources regarding loads, generation, transfers, etc. Very close attention was also paid to historical data from summer 2003 in producing these cases for 2004. "Stressed" cases were created by adding transfers at the FCITC level for use in AC thermal and voltage performance analysis. DC and AC load flow analysis was performed on the peak load model as well as the stressed transfer cases. A one line diagram of the Ohio EHV system produced from the peak load base case (no contingency) is provided on the next page. Similar diagrams and more detailed descriptions of the transfer cases are provided in the Performance Analysis section of this report.

[redacted] For the purposes of this study most initial analysis was completed with Ohio IPPs modeled out of service. The IPPs were then dispatched individually or in combination with others to show their individual or combined effects to the system. No area IPPs have been added to the system since summer 2003.

Other changes to the system model since summer 2003 include:

[redacted]

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ROANOKE TRANSMISSION REGION
2004 SUMMER – BULK TRANSMISSION APPRAISAL

By Rosalyn Navarro

SUMMARY

System performance for summer 2004 in the Roanoke transmission region is expected to be adequate. The forecasted connected APCO load, [redacted] for the 2004 summer season is [redacted] more than the forecasted load for 2003 Summer, [redacted] Various system conditions were simulated, including single and double transmission contingencies and power transfers through the AEP transmission system. Transfers to the [redacted] have the most detrimental impact on the Roanoke Transmission Region and are the key focus of this report.

Study results indicate that with all facilities in service and in the absence of heavy transfers to the [redacted] and [redacted] the bulk transmission system in the Appalachian area should perform adequately during anticipated conditions for the 2004 summer season. However, certain [redacted] contingencies in the Roanoke transmission area (including facilities in neighboring systems) are expected to cause overloads and other problems, especially when [redacted] to [redacted] transfers through the area are heavy. Critical [redacted] contingencies include, but are not exclusive to the following:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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FACILITY RATINGS

The diagrams in the following pages show the normal and emergency ratings for summer and winter (yellow pages) assumed in the SPA studies. For each facility, the listed ratings were determined by the most limiting element(s) either on the line itself, at the terminal stations, or at any intermediate (two-outlet) substation. The ratings were calculated using the criteria summarized below. With the exception of transformers, the summer ambient is 35°C (95°F) and the winter ambient is 2°C (35°F). For transformers, the summer and winter values are 30°C (86°F) and 10°C (50°F), respectively. The emergency ratings are generally based on a 24 hour period.

Buses and Risers

1 MPH wind, Normal-conductor temperature 85°C (Copper), 95°C (Aluminum & ACSR). Emergency-conductor temperature 115°C-120°C (Aluminum & Copper), 130°C (ASCR).

Circuit Breakers

Summer - 105% of nameplate rating
Winter - 130% of nameplate rating

Conductors

2 MPH wind. Normal-conductor temperature 95°C (203°F). Emergency-conductor temperature 130°C-205°C (266°F-401°F).

Current Transformers

Normal - 100% of nameplate rating
Emergency - 120% of nameplate rating

Disconnect Switches

Summer: normal/emergency - 109%/134% of nameplate rating
Winter: normal/emergency - 145%/160% of nameplate rating

Series Reactors

Normal - 100% of nameplate rating
Emergency - 100% of nameplate rating

Series Capacitors

Normal - 100% of nameplate rating
Emergency - 110% of nameplate rating

Wave Traps

Summer: normal/emergency - 102%/107% of nameplate rating
Winter: normal/emergency - 116%/120% of nameplate rating

Transformers

The ratings of all EHV and 345/138 kV transformers were determined on an individual basis by the Transmission Station Engineering and Standards Department. Refer to the Station Standards, Transformer Loading Guide for details of the rating criteria.

Notes

In January 1994 AEP issued Report No. 786 (Rev.), "A Guide for Maximum Temperature and Ampacity of Bare Overhead Conductors." These guidelines establish a range of permissible emergency conductor temperatures for various types of conductors, which in general allow for higher emergency ratings. However, the report cautions that the new temperature limitations may exceed sag limitations. Therefore, although most conductor limitations shown here follow the new guidelines, individual investigation by the Electrical Systems Engineering Division will be requested when planning studies or system conditions indicate possible loading above the "normal" rating.

In some instances where a higher equipment rating was desirable, an individual determination was made by the Electrical Systems Engineering Division.

Tieline ratings are determined by the company owning the limiting element(s), and are mutually agreed upon by AEP and the interconnecting company.

Most ratings listed for Columbus Southern Power Company lines were determined by CSP personnel prior to incorporation into the AEP system, using different criteria. Ratings for such lines will be reevaluated as needed.

Ratings for non-AEP facilities are the latest provided by the companies which own them.

Steady state stability and voltage loadability limited facilities may have several ratings depending on the conditions, contingency, or the actions required in the operating procedure. The following diagrams show the rating that reflects the base case conditions. See the appropriate operating procedure for further details.

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ABBREVIATIONS

I. ORGANIZATIONS

ECAR	East Central Area Reliability Coordination Agreement
AEWC	Allegheny Energy Wheatland (CIN Interconnection)
AEWI	Allegheny Energy Wheatland (IPL Interconnection)
AEP	American Electric Power System
AP	Appalachian Power Company
CS	Columbus Southern Power Company
IM	Indiana Michigan Power Company
KP	Kentucky Power Company
OP	Ohio Power Company
AMPO	American Municipal Power - Ohio, Incorporated
AP	Allegheny Power
BREC	Big Rivers Electric Corporation
BUCK	Buckeye Power, Incorporated
CIN	Cinergy Corporation
CGE	The Cincinnati Gas & Electric Company
PSI	PSI Energy, Incorporated
CPP	Cleveland Public Power
DEVI	Duke Energy Vermilion (CIN Interconnection)
DELO	Duke Energy Lawrence County Ohio (AEP Interconnection)
DEWO	Duke Energy Washington County Ohio (AEP Interconnection)
DLCO	Duquesne Light Company
DPL	The Dayton Power and Light Company
EKPC	East Kentucky Power Cooperative, Incorporated
FE	FirstEnergy
CEI	The Cleveland Electric Illuminating Company
OE	Ohio Edison System
TE	The Toledo Edison Company
HE	Hoosier Energy Rural Electric Cooperative, Incorporated
IMPA	Indiana Municipal Power Agency
IPL	Indianapolis Power & Light Company
IPRV	Illinois Power Riverside (AEP Interconnection)
ITC	International Transmission Company
DECO	The Detroit Edison Company
LGEE	LG&E Energy Corporation
KU	Kentucky Utilities Company
LGE	Louisville Gas & Electric Company
MCCP	Municipal Cooperative Coordinated Pool - Michigan
MCV	Midland Cogeneration Venture
MECS	Michigan Electric Coordinated System
METC	Michigan Electric Transmission Company
CONS	Consumers Energy
NIPS	Northern Indiana Public Service Company
OVEC	Ohio Valley Electric Corporation
SIGE	Southern Indiana Gas and Electric Company
WVPA	Wabash Valley Power Association
FRCC	Florida Reliability Coordination Council
EQ-FRCC	Powerflow Equivalent of FRCC Region
MAAC	Mid-Atlantic Area Coordination Group
AE	Atlantic Electric (Conectiv)

BG&E	Baltimore Gas and Electric Company
DP&L	Delmarva Power and Light Company (Conectiv)
JCP&L	Jersey Central Power and Light Company
METED	Metropolitan Edison Company
PECO	PECO Energy
PENELEC	Pennsylvania Electric Company
PEPCO	Potomac Electric Power Company
PJM500	PJM Interconnection - 500 kV System
PP&L	Pennsylvania Power & Light Company
PSE&G	Public Service Electric and Gas Company
UGI	UGI Utilities
MAIN	Mid-America Interpool Network
AMRN	AMEREN Corporation
CIPS	Central Illinois Public Service Company
UE	Union Electric System
CE	Commonwealth Edison Company
CILCO	Central Illinois Light Company
CWLP	City Water Light and Power (Springfield, Illinois)
EEI	Electric Energy, Incorporated
EMO	East Missouri Subregion of MAIN
EQ-MAIN	Partial Powerflow Equivalent of MAIN Region
IMEA	Illinois Municipal Electric Agency
IP	Illinois Power Company
NI	Northern Illinois Subregion of MAIN
SCILL	South Central Illinois Subregion of MAIN
SIPC	Southern Illinois Power Cooperative
WUMS	Wisconsin-Upper Michigan Systems Subregion of MAIN
MAPP	Mid-Continent Area Power Pool
EQ-MAPP	Powerflow Equivalent of MAPP Region
NPCC	Northeast Power Coordinating Council
EQ-NPCC	Partial Powerflow Equivalent of NPCC Region
NYISO	New York Independent System Operator
NYPP	New York Power Pool
HONI	HydroOne (Canada)
IMO	Independent Market Operator (Canada)
SERC	Southeastern Electric Reliability Council
AECI	Associated Electric Cooperative, Incorporated
BCA	Batesville Control Area
CPLE	Carolina Power & Light Company (East)
CPLW	Carolina Power & Light Company (West)
DENL	Duke Energy, North Little Rock
DOE	Department of Energy
DUKE	Duke Energy Control Area
LAGN	Louisiana Generating Company
EQ-SERC	Partial Powerflow Equivalent of SERC Region
NCEMC	North Carolina Electric Membership Cooperative
SC	Santee Cooper (South Carolina Public Service Authority)
SCEG	South Carolina Electric & Gas
SOCO	Southern Control Area
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas Subregion of SERC
VAP	Virginia Power

SPP	Southwest Power Pool
EQ-SPP	Powerflow Equivalent of SPP Region

II. **STUDY TERMS**

ATC	Available Transfer Capability
CRV	Curtailment Reference Value
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GSRF	Generation Shift Response Factor
IITC	Installed Incremental Transfer Capability
LEER	Lake Erie Emergency Re-dispatch Procedure
LMP	Locational Marginal Pricing
LODF	Line Outage Distribution Factor
MEN	MAAC-ECAR-NPCC
MET	MAIN-ECAR-TVA
MMWG	Multiregional Modeling Working Group
NDC	Net Demonstrated Capability
NSC	Net Seasonal Capability
NERC	North American Electric Reliability Council
NITC	Normal Incremantal Transfer Capability
NTTC	Normal Total Transfer Capability
OTDF	Outage Transfer Distribution Factor
PAR	Phase Angle Regulator
PTDF	Power Transfer Distribution Factor
QFW	Queenston Flow West Interface in Ontario Hydro
RCP	Reliability Coordination Plan
SCITC	Second Contingency Incremental Transfer Capability
TDF	Transfer Distribution Factor
TLR	Transmission Loading Relief Procedure
VAST	VACAR-AEP-Southern-TVA
VEM	VACAR-ECAR-MAAC

SPECIAL PROCEDURES

I. INTRODUCTION

This subsection lists and briefly describes various operating procedures that have been developed to enhance the performance in specific areas of the bulk power system. The procedures described herein, all of which result in changes in network configuration or generation dispatch levels, generally are implemented to achieve one or more of the following goals:

1. To reduce facility loadings to within equipment thermal capabilities;
2. To maintain acceptable transient stability margins at generating stations;
3. To improve area reliability without exceeding the short circuit capabilities of circuit breakers;
4. To insure adequate voltage levels or steady state stability margins are maintained.

Procedures relating to AEP facilities and tielines with neighboring systems are found in Part II. The listing is separated by AEP's Transmission Regions. Operating procedures developed by AEP's neighbors are described in Part III. Here the listing is alphabetic by company. The provision of a consolidated listing of new and established procedures should aid system operators in maximizing utilization of the bulk power system. Likewise, planning engineers should benefit in terms of the more accurate modeling of projected system conditions obtained by including likely operator responses to particular system conditions in planning studies.

Additional details of the procedures may be available by contacting members of East Bulk Transmission Planning or East Area Transmission Planning.

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SYSTEM PERFORMANCE ANALYSIS REPORT

Prepared by the
East Transmission Planning Section
of the Transmission Planning Department

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4. Added pages for Summer 1999 review	05/99
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6. Added pages for Summer 2000 review	05/00
7. Added pages for Winter 2000/01 review	12/00
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10. Added pages for Summer 2002 review	05/02
11. Added pages for Winter 2002/03 review	12/02
12. Added pages for Summer 2003 review	05/03
13. Added pages for Winter 2003/04 review	12/03
14. Added pages for Summer 2004 review	05/04
15. Added pages for Winter 2004/05 review	12/04

LAYOUT OF REPORT

This report has main sections and subsections. The report will be maintained as a current document through periodic updating of selected pages. This will generally include material related to system performance and the modeling used in load flow cases. Data that is normally unchanged (e.g., tap data and generator capabilities) is included in an Appendix.

First, there is a section of summaries of system performance. There is an executive summary for all of eastern AEP, followed by more detailed summaries for each of the Transmission Planning Regions – Ft. Wayne, Columbus and Roanoke.

Next, there is a section which details some aspects of the data used in load flow models for projected peak conditions, including projected loads, projected power transfers, and transcriptions of a no-contingency load flow cases (for both projected peak load and an extreme weather peak load).

Then, there is a major section that details the expected performance in upcoming load periods. The section consists of Key Facility tables that identify the transmission facilities that are potential overload or voltage problems. The tables are listed by the limiting facility for each of the three Transmission Planning Regions. The rating and limiting equipment are identified. Transmission outages, generation changes, and transfers that can have a significant impact on the limiting facility are also provided along with the respective response factors. The expected percent overload of the critical facility for the stressed conditions, which include the listed contingencies and transfers, is provided. Details of the listed transfers are provided in each section behind the Key Facility tables.

The final section is an Appendix. It contains relatively stable data, including: circuit ratings (for summer and winter), transformer tap data, generating unit capability data, a list of abbreviations, and a description of operating procedures across the system.