OHIO VALLEY ELECTRIC CORPORATION

2010 TRANSMISSION PLAN

DRAFT

Prepared On OVEC's behalf by:
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American Electric Power

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Foreword

American Electric Power (AEP) completed this Transmission Performance Appraisal on behalf of the Ohio Valley Electric Corporation (OVEC)

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Executive Summary

The OVEC system in the near-term planning horizon is projected to meet the requirements of both OVEC planning criteria and the applicable NERC Transmission Planning Standards.

Steady State studies were performed examining performance of the planned OVEC 2015 system at both summer peak and shoulder peak load levels. Transfer analysis examined incremental transfer capabilities for transfers into, out of and across the OVEC system. Sensitivity analysis examined the changes in transfer capabilities resulting from varying the generation dispatches used to simulate these transfers.

Stability studies were performed to confirm that performance of the Kyger Creek plant in the context of the new transmission outlet configuration complies with the requirements of the NERC Transmission Planning Standards. Short circuit analysis was performed to confirm that the expected interrupting duties are within the capabilities of the existing and planned circuit breakers.

Introduction

This report provides an assessment of the Ohio Valley Electric Corporation (OVEC) transmission system as required by the NERC Transmission Planning Standards. This assessment, and the studies it documents, is also an integral part of the open planning process instituted in response to FERC Order 890.

System Description

The Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), were organized and their transmission systems constructed in the years 1952-1956. OVEC/IKEC was formed by 15 investor-owned electric utility companies (Sponsors) for the express purpose of supplying the electric power requirements of a single retail customer, the U.S. Department of Energy's (DOE) uranium enrichment project (Project) located near Portsmouth, Ohio. Due to the highly critical nature of the DOE load, stringent design criteria were adopted for planning and constructing the OVEC/IKEC System.

The entire OVEC/IKEC System is considered to be part of the bulk electric system, as it is primarily an EHV network. The system map is shown below. The only non-EHV transmission facilities are 138 kV facilities associated with interconnections to the systems of several Sponsors. The OVEC system is highly interconnected. Interconnecting facilities consist of eight 345 kV lines, the high-side connections to four neighboring system 345/138 kV transformers, and three 138 kV lines. The strong internal EHV network and number of interconnections relative to the size of the system precludes a need to analyze sub areas within OVEC, or to use more detailed models than are used in regional studies.

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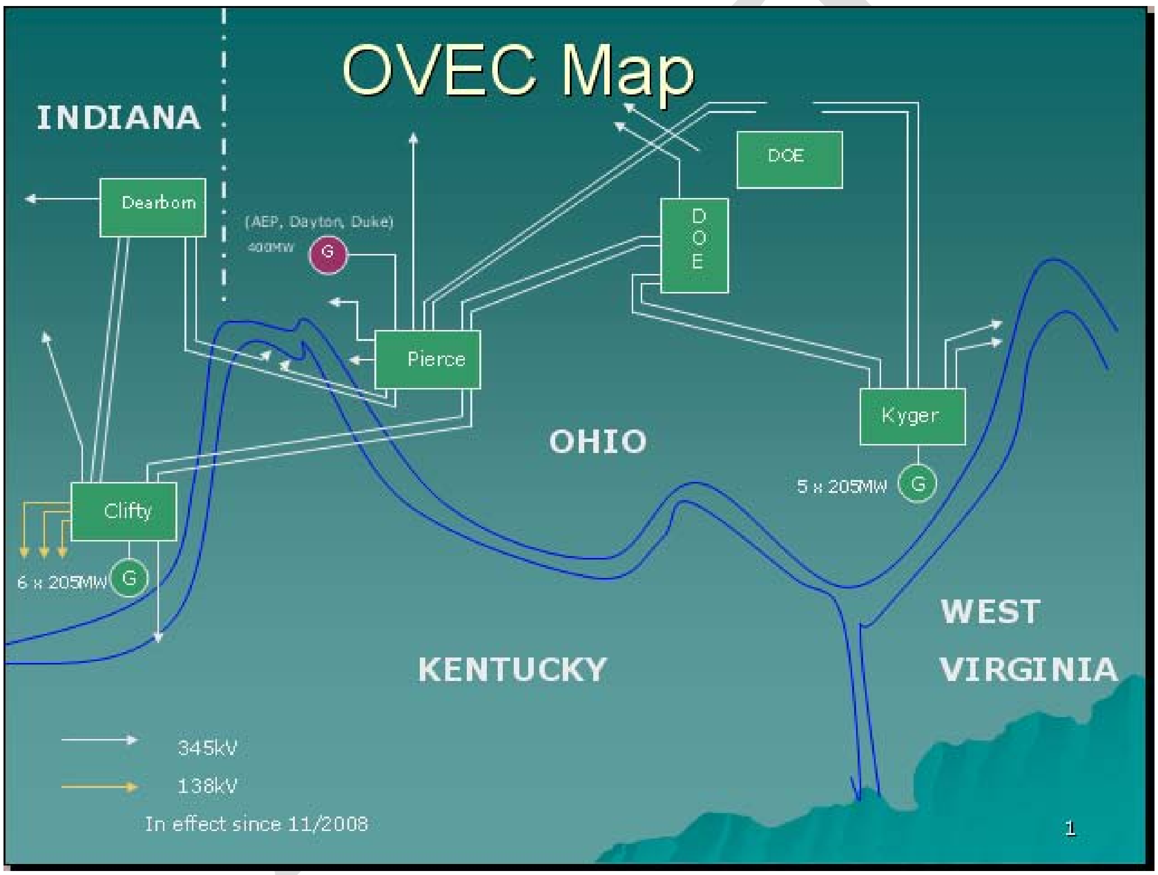
Summary of Limits and Contingencies

The minimal DOE load today is served from the remaining DOE-owned 345 kV station within the Project's boundaries. Two double-circuit tower 345kV lines and one single-circuit 345 kV line from OVEC/IKEC and Sponsors' stations supply this station. A second, similar station was removed from service in November 2008. Reconnection of the lines (bypassing the former station site) is scheduled to be completed 9/30/2010. The OVEC/IKEC System has eleven generating units located at two plants with a total capacity of about 2300 MW. The 414 MW Beckjord Unit 6 (DEM/DPL/AEP) is also connected to the OVEC system at the Pierce station. Prior to September 2001 a portion of the OVEC generation was delivered to the DOE load based on the demand established in OVEC/IKEC's contract with DOE, and any remaining generation was sold to the Sponsors on an ownership participation basis. Since September 2001 all generation, with the exception of required operating reserves, has been made available to the Sponsors.



Review of Recent Operating Conditions and System Changes

As outlined in Attachment M of the OVEC Tariff, the following factors are to be addressed in developing the OVEC transmission plan:

> Review of recent operating conditions, such as NERC Transmission Loading Relief events or MISO and PJM LMP binding constraints that may indicate

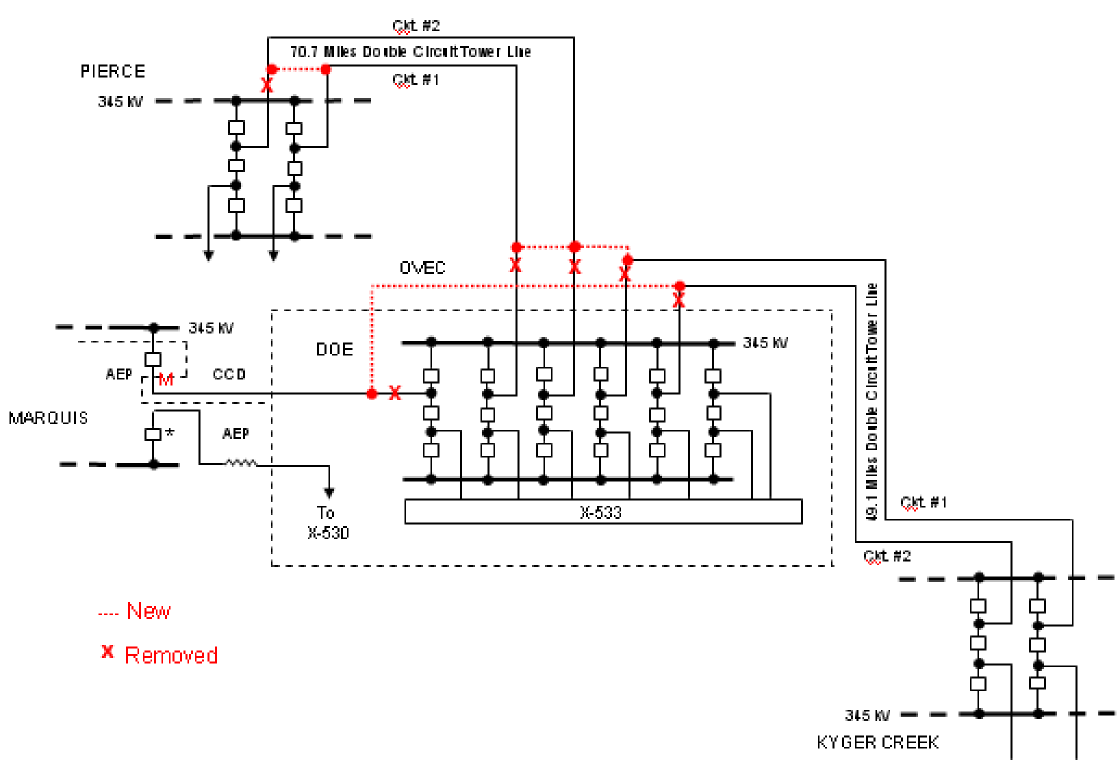
developing reliability concerns on the OVEC system; t*here were no TLR events involving OVEC facilities declared during 2009.*

• Requests for connection to OVEC facilities -- *None*
• Requests for service into, out of or through the OVEC Transmission system -- *None*;
• Projections of future load or generation changes within OVEC -- *Minimal*;
• Projections of OVEC major transmission equipment or systems approaching end-of-useful life – *Sixteen 345 kV OCB's and associated P&C equipment at Kyger Creek and two 345 kV OCB's at Dearborn.*

New Facilities

Since retirement of the DOE-owned X533 345 kV station in November 2008, the five 345 kV circuits formerly terminated at the station have been out of service. The reconfiguration of the affected circuits, shown in the diagram below, is scheduled to be completed on 9/30/2010. Replacement of antiquated circuit breakers and associated relays and controls at Kyger Creek associated with these circuits has also been performed during the extended outage.

CHANGES TO BYPASS DOE X-533 STATION



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Abnormal Conditions

Following completion of the reconfiguration of the former X533 circuits, there is no expectation that abnormal conditions will exist on the OVEC system for extended periods.

Study Base Cases

Assumptions

The models used for the steady state analyses represent the OVEC and adjacent transmission systems as planned for 2015. The 2015 summer period represents the latter portion of the years 1-5 planning horizon. Per the TPL standards, assessments are required to address conditions beyond the 5 year horizon only as needed to address identified marginal conditions that may have longer lead time solutions.

Two models were used:

- **2015 Summer Peak** --The initial base case model for the 2015 summer peak study was derived from the 2009 series MMWG 2015 summer peak case. Conditions represented in this model include projected peak loads for the 2015 summer period, with all available facilities in service and anticipated firm transactions. Because the OVEC Transmission system consists entirely of 345 kV and 138 kV facilities, they are fully represented in the RFC models. There are no additional OVEC facilities expected to be in service for 2015 summer that were not represented in the RFC models. For OVEC, key assumptions consist of an area load of 35 MW, with 2000 MW delivered to the OVEC Sponsors. In determining the level of OVEC-Sponsor interchange to be modeled, it is assumed that the equivalent of one of the eleven OVEC generators is not available. Because the OVEC units are all of similar size, age, and operating history, the assumption is made that they will all be dispatched at similar levels.

- **2015 Shoulder load** -- The initial base case model for the OVEC 2015 summer peak study was derived from the RFC 2015 Shoulder Peak Study base case.

  The RFC 2015 Shoulder load study conducted a near-term assessment of the expected performance of the Reliability*First* transmission system for the 2015 Shoulder conditions, with wind generation operating at 90% of nameplate and pumped storage generation operating in pumping mode. The 90% wind output is at or slightly above the maximum output levels reported for aggregations of multiple, geographically dispersed wind farms, e.g., across the entire Midwest ISO footprint. For the purpose of this study, the shoulder load period was defined as those hours when the overall system load is at 55-65% of the summer peak. The high level of wind output resulted in significant differences in base

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interchange assumptions from those contained in the MMWG 2015 Peak load model. The following table summarizes the differences:

	Interchange (MW)		
Study Area	2015 Summer Shoulder	2015 Summer Peak	Difference
PJM East	2980	9104	-6124
PJM South	-7562	-6338	-1224
PJM West	511	-486	997
PJM Northern Illinois	5484	-210	5694
WUMS	1336	-304	1640
LAKES	-2470	-2578	108
Midwest ISO South	228	274	-46
OVEC	1997	2000	-3
NPCC	-6483.6	-7278.3	795
SERC*	-4751	1329.8	-6081
SPP	-976.6	-780.8	-196
MRO**	871.3	929	-58

* SERC excluding DVP and Southern Companies
** MRO excluding WUMS

For OVEC, key assumptions in this model consist of an area load of 35 MW, with 2000 MW delivered to the OVEC Sponsors, similar to a peak load model. This assumption is based on the historical high utilization of any available OVEC generation.

The Shoulder load studies attempted to identify an operating edge and robustness of the transmission system by identifying constraints to various simulated transfer scenarios. This typically involved stressing the transmission system beyond planning and operating criteria. Given the more stringent underlying assumptions utilized in this assessment, the transmission constraints identified in this study are not necessarily an indication of a need for transmission reinforcements due to violation of planning or operating criteria/standards.

<u>Analysis</u>
The PTI/Siemens PSS/E and/or MUST analysis tools were used to screen for violations of performance criteria under various outage conditions. MUST was also used to determine First Contingency Incremental Transfer Capabilities (FCITCs) for 12 different transfer directions expected to affect flows into, out of or through the OVEC system.

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Summary of Limits and Contingencies

These FCITCs are not an indication of the transmission network capability to accommodate a specific transfer or transmission service request. However, they serve as a surrogate for a variety of possible operating conditions, and provide a means to evaluate the strength of the system as it is stressed by these varied conditions. The following transfer directions were studied

Test Transfer Directions			
FROM	**TO**	**2015 Summer Peak Load FCITC (MW)**	**Limit**
OVEC	Sponsors*	100+	None
Sponsors*	OVEC	200-650	Trimble County – Clifty Creek 345 kV
LGEE	DEM	200-500	Trimble County – Clifty Creek 345 kV
DEM	LGEE	4000+	Clifty Creek – Northside 138 kV
LGEE	AEP	200-350	Trimble County – Clifty Creek 345 kV
AEP	LGEE	4000+	None
EKPC	DEM	500+	None
EKPC	DAY	500+	None
TVA	ITC	1200	Trimble County – Clifty Creek 345 kV
ITC	TVA	1500+	None
AMIL	DVP	2000	Trimble County – Clifty Creek 345 kV
DVP	AMIL	2000+	None
AMIL	PJM	1700+	Trimble County – Clifty Creek 345 kV

+ Not limited by transmission conditions at the value given
*The deliveries involving the OVEC Sponsoring companies are allocated in the following manner:

AEP 61.45% (Includes Buckeye share)
AP 3.5%
FE 11.5%
DEM 9.0 %
DAY 4.9%
SIGE 1.5%
LGEE 8.15%

The MUST sensitivity analysis capabilities were also used to determine the generation participation changes that would produce the worst FCITC results. In addition to providing insight into the variability of FCITC limitations for different generation dispatches, these analyses identify plants where future capacity changes could affect performance of the OVEC system.

<u>Steady State Analysis Results</u>

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Summary of Limits and Contingencies

NERC Planning Standard TPL-001-0.1 Category A (System Normal) Conditions

- Peak conditions: No OVEC facility loadings exceed the Normal ratings, and voltages are within criteria.

- Shoulder conditions: No OVEC facility loadings exceed the Normal ratings, and voltages are within criteria.

NERC Planning Standard TPL-002-0b Category B (N-1) Conditions

More than 5000 Category B contingencies were simulated.

- Peak conditions: All OVEC facility loadings are below the Emergency ratings and no voltage violations were found.

- Shoulder conditions: All OVEC facility loadings are below the Emergency ratings. No OVEC voltage violations were identified.

NERC Planning Standard TPL-003-0a Category C (N-2) Conditions

More than 11,500 Category C contingencies were simulated.

Peak conditions: All OVEC facility loadings are below the Emergency ratings.

Shoulder conditions: All OVEC facility loadings are below the Emergency ratings. One Category C-3 contingency produced loadings at 99% of the Emergency Rating of the Kyger-Sporn 345 kV [OVEC-AEP] tieline. Future studies will need to continue to monitor performance in this area.

NERC Planning Standard TPL-004-0 Category D (Extreme N-2) Conditions

Because most OVEC stations have a fully developed Breaker and ½ layouts, steady state simulation of most category D events is already addressed under category C. The exceptions that apply to the OVEC system include Category D contingency sub-types 8 and 9, which involve loss one of voltage level at a substation or switching station, including transformation, and subtype 10, which involves loss of all generating units at a station.

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Summary of Limits and Contingencies

Station outage contingencies were simulated in studies performed in 2008, evaluating the proposed bypass of the X533 station. Since the network configuration in the vicinity of the OVEC system is not expected to change significantly through the near-term planning horizon, the results of those studies remain valid. No indication of cascading was identified in those studies.

Short Circuit Assessment

Studies were performed evaluating the expected short circuit interrupting duties relative to the capability of the existing and planned circuit breakers. Studies show that no OVEC circuit breakers are expected to be called upon to interrupt fault currents in excess of their capability. The lowest margins are found at Kyger Creek, on CBs which are slated for replacement by the end of 2011. These studies are documented in a separate report, provided as Appendix D.

Stability Studies and Results

Studies were performed to evaluate the stability performance of the Kyger Creek plant with the new transmission outlet configuration (bypassing the former X533 site.) The plant performance was found to meet the requirements of both the OVEC Transmission Testing Criteria and NERC Reliability Standards. These studies are documented in a separate report, provided as Appendix E.

Operating Procedures/Special Protection Systems

OVEC has no Special Protection Systems. Operating procedures to reduce flows through the Clifty Creek-Carrolton 138 kV tieline between OVEC and E.On and the Kyger Creek-Sporn 345 kV tieline between OVEC and AEP. They are described in Part 5 of the OVEC response to FERC Form 715, and reproduced in Appendix B of this report.

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Appendices

Appendix A – Testing Criteria

(Excerpt from the OVEC response to FERC FORM 715 - ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

4. TRANSMISSION TESTING CRITERIA

4.1 Steady State Testing Criteria

The planning process for OVEC/IKEC's transmission network embraces two major sets of testing criteria to ensure reliability. The first set includes all critical single and double contingencies. The second set includes more severe multiple contingencies (such as those described in ECAR Document No. 1) and is primarily intended to test the potential for system cascading.

For OVEC/IKEC transmission planning, the testing criteria are deterministic in nature; these outages serve as surrogates for a broad range of actual operating conditions that the power system will have to withstand in a reliable fashion.

4.1.1 Single and Double Contingencies

Contingencies include the forced or scheduled outage of generating units, transmission circuits, transformers, or other equipment. In general, a single contingency is defined as the outage of any one of these facilities. Due to the interconnected nature of power systems, testing includes outages of facilities in neighboring systems. A single facility is defined based on the arrangement of automatic protective devices. Generally, double circuit tower outages, breaker failures, station outages, common right-of-way outages, and other common mode failures have substantially lower probabilities of occurrence than the outage of a single transmission facility and are, therefore, not considered single contingencies.

Double contingencies, being a more severe test of system performance, are used as a surrogate for the significant uncertainties that are inherent in the planning process.

Operational planning studies consider up to two key outages in effect prior to the next (third) contingency. It is assumed that all operator adjustments required for the prior outages have been implemented. The number of prior outages depends on the strength of the transmission system and the number of variables to be considered in developing effective operating guidelines. Clearly, as the number of concurrent contingencies increases, it will become increasingly difficult to meet the required performance limits (see Section 3), even with special operating procedures.

The number of outages actually occurring on the system can exceed the number assumed for study purposes. Operational planning engineers can evaluate those conditions, as needed.

4.1.2 Severe (ECAR Type) Contingencies

The more severe Reliability Assessment Criteria required in ECAR Document No. 1 are primarily intended to prevent uncontrolled area-wide cascading outages under adverse but credible conditions. OVEC/IKEC, as a member of ECAR, plans and operates its transmission system to meet the criteria of ECAR Document No. 1. However, new facilities would not be committed on the basis of local overloads or voltage depressions following the more severe ECAR type multiple contingencies unless those resultant conditions were expected to lead to widespread, uncontrolled outages.

In operational planning studies, the purpose of studying multiple contingencies and/or high levels of power transfers is to evaluate the robustness of the system. Where conditions are identified that could result in significant equipment damage, uncontrolled area-wide power interruptions, or danger to human life, operating procedures will be developed, if possible, to avoid or minimize the adverse effects. It is accepted that the defined performance limits could be exceeded on a localized basis during the more severe ECAR type multiple contingencies, and that there could be resultant minor equipment damage, increased loss of equipment life, or limited loss of customer load. Normally, operating procedures to mitigate uncontrolled area-wide power interruptions are only used on an interim basis until facility additions can be put in place to restore acceptable reliability levels.

4.2 Stability Testing Criteria

Stability testing covers the entire range of power system dynamics from "first swing" transient stability to the longer term oscillatory and steady-state stability. This testing is an essential complement to the steady state analysis embodied in the load flow testing described above.

Power plant transient stability is a very important consideration since loss of synchronism of a generating unit or an entire generating plant, in addition to compounding the disturbance by the loss of generators, can lead to equipment damage. When simulating system contingencies affecting power plant stability, various types of fault and network conditions are analyzed using the transient stability performance testing criteria outlined in Appendix C.

Steady-state and oscillatory stability performance problems may be initiated by a wide variety of contingencies or operating conditions on the transmission network. Therefore, a wide variety of network disturbances are considered when testing for steady-state and oscillatory stability problems.

Acceptable performance limits for all types of stability performance are discussed in Section 3.

4.3 Power Transfer Testing Criteria

The power transfer capability between two interconnected systems (or sub-systems) with all facilities in service or with one or two critical components out of service, indicates the overall strength of the network. Many definitions of power transfer capability are possible, but uniformity is highly desirable for purposes of comparison. Furthermore, transfer capability, however defined, is only accurate for the specific set of system conditions under which it was derived. Therefore, the user of this information needs to be aware of the conditions under which the transfer capability was determined and those factors that could significantly influence the capability.

OVEC/IKEC has adopted the definitions of transfer capability, published by NERC in "Transmission Transfer Capability", dated May 1995. The most frequently used transfer capability definition is for First Contingency Incremental Transfer Capability (FCITC) and is quoted below from the referenced NERC publication:

First Contingency Incremental Transfer Capability

"FCITC 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:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits."

First Contingency Total Transfer Capability (FCTTC) is similar to FCITC except that the base power transfers (between the sending and receiving areas) are added to the incremental transfers to give total transfer capability. ECAR has adopted guidelines for interpreting and applying the NERC transfer capability definitions, and OVEC/IKEC uses these guidelines in its internal studies as well.

While the first contingency transfer capabilities are the most frequently used measure of system strength, transfer capabilities also can be calculated for "no contingency" and "second contingency" conditions.

In April 1996 the Federal Energy Regulatory Commission issued two rules -- Orders No. 888 and 889. Two aspects of these rules are "open access" to the transmission systems of integrated utilities and the posting of available transfer capability. The ability of a transmission system to permit power transfers is defined by several terms, namely:

Firm Available Transfer Capability (ATC)
Firm Total Transfer Capability (TTC)
Non-firm ATC
Non-firm TTC
Transmission Reliability Margin
Capacity Benefit Margin

The ATC/TTC values provide an indication of the ability of the transmission system to support transfers. Firm ATC is the level of additional transfer capability remaining in the physical network for further commercial activity over and above existing commitments for future time periods. The ATC/TTC values are calculated for transactions in both directions between OVEC/IKEC and directly connected control areas and for selected commercially viable through paths across the OVEC/IKEC System. ATC values are the lesser of network capability or contract path capacity (i.e., the total capability of interconnections to a neighboring control area). Firm TTC is determined by adding firm schedules and/or reservations to the ATC values.
Non-firm ATC are calculated in a manner similar to that used to calculate the firm values, except that both firm and non-firm transactions are included in the calculations.
TRM is the amount of transfer capability reserved to ensure that the transmission network is secure under a range of uncertainties in operating conditions. These uncertainties include generation unavailability, load forecast error, load diversity, unknown outages in neighboring systems, and variations in generation dispatch. The TRM is applied directly to facility ratings for calculations of firm ATC/TTC by adjusting the thermal rating of the critical facility(ies) down to 95% of the seasonal emergency capability. TRM is applied only to firm ATC calculations.

CBM is the amount of transfer capability reserved by Load Serving Entities to ensure access to generation from interconnected systems to meet generation reliability requirements. The total OVEC/IKEC CBM value is based upon generation reserve requirements. CBM is subtracted as a fixed MW amount from the firm OVEC/IKEC TTC import capability. The CBM is allocated among OVEC/IKEC’s interfaces and the amount allocated to individual interfaces is based upon the lowest of: 1) the estimated long term generation reserve of the adjoining control area, 2) the transmission interconnection capability with each of the adjoining control areas, and 3) the FCTTC with each of the adjoining control areas. However, since the DOE Project load has been reduced to a very low level, the CBM for the OVEC System has been reduced to zero.

OVEC/IKEC methodologies to calculate these values are consistent with the "NERC Available Transfer Capability" and the "ECAR TTC/ATC Calculation/Coordination" documents.

4. TRANSMISSION TESTING CRITERIA

4.1 Steady State Testing Criteria

The planning process for OVEC/IKEC's transmission network embraces two major sets of contingency testing criteria to ensure reliability. The first set includes all significant single and double contingencies (NERC Categories B and C.) The second set includes more severe multiple contingencies (NERC Category D) and is primarily intended to test the potential for system cascading.

For OVEC/IKEC transmission planning, the testing criteria are deterministic in nature; these outages serve as surrogates for a broad range of possible operating conditions that the power system will have to withstand in a reliable fashion.

4.1.1 Single and Double Contingencies

Contingencies include the forced or scheduled outage of generating units, transmission circuits, transformers, or other equipment. In general, a single contingency is defined as the outage of any one of these facilities. Due to the interconnected nature of power systems, testing includes outages of facilities in neighboring systems. A single facility is defined based on the arrangement of automatic protective devices. Generally, double circuit tower outages, breaker failures, station outages, common right-of-way outages, and other common mode failures have substantially lower probabilities of occurrence than the outage of a single transmission facility and are, therefore, not considered single contingencies.

Double contingencies, being a more severe test of system performance, are used as a surrogate for the significant uncertainties that are inherent in the planning process. A double contingency can be defined as an outage of any two facilities. Double contingencies can be categorized by industry standards as either N-2 (an overlapping outage of two facilities with no corrective action following the first contingency) or N-1-1 (this category allows system adjustments after the initial outage). Double contingency analyses are also frequently applied in facility planning studies. These tests provide additional insight regarding the need for transmission system enhancements.

Operational planning studies may consider up to two key outages in effect prior to the next (third) contingency. It is assumed that all operator adjustments required for the prior outages have been implemented. The number of prior outages depends on the strength of the transmission system and the number of variables to be considered in developing effective operating guidelines. Clearly, as the number of concurrent contingencies increases, it will become increasingly difficult to meet the required performance limits (see Section 3), even with special operating procedures.

The number of outages actually occurring on the system can exceed the number assumed for study purposes. Operational planning engineers can evaluate those conditions, as needed.

4.1.2 Extreme Contingencies

The more severe reliability assessment criteria required in NERC Reliability Standards are primarily intended to prevent uncontrolled area-wide cascading outages under adverse but credible conditions. OVEC/IKEC, as a member of Reliability*First*, plans and operates its transmission system to meet the criteria. However, new facilities would not be committed based on local overloads or voltage depressions following the more severe multiple contingencies unless those resultant conditions were expected to lead to widespread, uncontrolled outages.

In operational planning studies, the purpose of studying multiple contingencies and/or high levels of power transfers is to evaluate the strength of the system. Where conditions are identified that could result in significant equipment damage, uncontrolled area-wide power interruptions, or danger to human life, IROL operating procedures will be developed, if possible, to mitigate the adverse effects. It is accepted that the defined performance limits could be exceeded on a localized basis during the more severe multiple contingencies, and that there could be resultant minor equipment damage, increased loss of equipment life, or limited loss of customer load. Normally, operating procedures to mitigate uncontrolled area-wide power interruptions are only used on an interim basis until facility additions can be put in place to restore acceptable reliability levels.

In carrying out operational or facility planning studies, it is recognized that there are many protective and special controls on the system that must operate properly when an event occurs. These controls include but are not limited to: protective relays, circuit breakers, breaker failure schemes, quick reactor, or capacitor switching, rapid generating unit runback, automatic motor operated disconnects, and emergency generator tripping. The misoperation of any of these controls may result in equipment damage, but should not result in widespread power interruptions or danger to human life.

4.2 Stability Testing Criteria

Stability testing covers the entire range of power system dynamics from "first swing" transient stability to the longer-term oscillatory and steady state stability. This testing is an essential complement to the steady state analysis embodied in the load flow testing described above.

Maintaining power plant transient stability is essential because loss of synchronism (or instability) of a generating unit or an entire generating plant can lead to equipment damage and severe power system transient swings. Instability may further compound a disturbance by causing the tripping of the unstable generators and possibly other equipment. When simulating system contingencies affecting power plant stability, various types of fault and network conditions are analyzed in accordance with the transient stability disturbance testing criteria outlined in Appendix B.

Steady state and oscillatory stability performance problems may be initiated by a wide variety of contingencies or operating conditions on the transmission network. Therefore, wide varieties of Appendix B network disturbances are considered when testing for steady state and oscillatory stability problems. Acceptable performance limits for all types of stability performance are discussed in Section 3.

The disconnection of generation due to a disturbance is distinct from instability. Instability refers to loss of synchronism or pole slipping when the generation remains physically connected. Disconnection results in generator overspeed followed by turbine shutdown in response to protective relay action. Systems are planned such that disconnection does not occur for single contingencies. Disconnection may occur during Appendix B disturbance scenarios involving the outage of more than one transmission element, or common-failure mode disturbances such as bus outages, as a consequence of isolating faulted facilities or other system design considerations. Disconnection under these circumstances is considered to be acceptable whereas instability is not.

4.3 Power Transfer Testing Criteria

The power transfer capability between two interconnected systems (or sub-systems) with all facilities in service or with one or two significant components out of service, indicates the overall strength of the network. Many definitions of power transfer capability are possible, but uniformity of definition is highly desirable for purposes of comparison. Furthermore, transfer capability, however defined, is only accurate for the specific set of system conditions under which it was derived. Therefore, the user of this information needs to be aware of the conditions under which the transfer capability was determined and those factors, which could significantly influence the capability.

OVEC/IKEC has adopted the definitions of transfer capability, published by NERC in "Transmission Transfer Capability," dated May 1995. The most frequently used transfer capability definition is for First Contingency Incremental Transfer Capability (FCITC) and is quoted below from the referenced NERC publication:

First Contingency Incremental Transfer Capability

"FCITC 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:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits."

First Contingency Total Transfer Capability (FCTTC) is similar to FCITC except that the base power transfers (between the sending and receiving areas) are added to the incremental transfers to give total transfer capability.

Appendix B – Special Procedures & Contingencies

(Excerpt from the OVEC response to FERC FORM 715 - ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

A. SPECIAL PROCEDURES

This section describes operating procedures that have been developed to mitigate problems identified on the transmission system and special modeling techniques used in the assessment of OVEC/IKEC system performance. Unless otherwise stated, these operating procedures are anticipated to be applicable indefinitely. As a result, they should be modeled in screening studies that evaluate future system performance. The procedures described herein generally are implemented to reduce facility loadings to within equipment thermal capabilities or to insure that adequate voltage levels or steady state stability margins are maintained.

<u>Clifty Creek-Carrolton 138 kV (OVEC-E.On)</u>
Past operating experience indicates that the Clifty Creek – Carrolton 138 kV tieline between OVEC and E.On may become heavily loaded anticipating loss of either Ghent Unit 1 (E.On) or Spurlock-N. Clark 345 kV (EKPC). Loading concerns would likely occur during periods of high north-to-south transactions, especially if these transfers coincide with high output at Trimble County (E.On) and reduced output at other E.On plants. If necessary, OVEC has agreed to open the Clifty Creek 345/138 kV transformer T-100A at the request of the PJM Reliability Coordinator to relieve the loading concerns.

<u>Kyger Creek - Sporn 345 kV (OVEC-AEP)</u>
Past operating experience indicates that the Kyger Creek - Sporn 345 kV tieline between OVEC and AEP may become heavily loaded by high levels of west-to-east transactions, especially if these transfers coincide with reduced output at any of several AEP plants east of this tieline. AEP and OVEC have agreed to open the Kyger Creek - Sporn 345 kV circuit, when necessary. However, opening this tieline will increase loadings on other OVEC-AEP tielines. Conditions on these facilities may restrict use of this procedure.

Kyger Creek Stability constraints

Following the de-energization of the DOE-owned X533 station, the Kyger Creek stability performance meets performance criteria, assuming that the four remaining outlets are all in service, as well as both X530 to Pierce circuits. During an outage of any one of the following: Kyger-Sporn, Kyger-X530 #1 or #2, or X530-Pierce #1 or #2 circuits, stability performance with full output from all five Kyger Creek units would not be acceptable for some subsequent Double-Circuit-Tower (DCT) line contingencies. Acceptable stability performance with the prior outage of one of the above named circuits can be maintained if Kyger Creek output is reduced by the equivalent of one Kyger Creek unit.

The areas of concern described above are those identified in the most recent performance appraisals conducted, based on the best available knowledge of interconnected system development, and expected operating conditions. The results of appraisals assuming different system conditions can be considerably different.

B. CONTINGENCY LIST

The following is a description of the contingencies that have been simulated in recent appraisals of the OVEC/IKEC system performance, to meet the requirements of the ECAR Compliance Program. This list is not exhaustive, but is designed to screen OVEC/IKEC system performance to verify that ECAR reliability criteria are being met and that OVEC system performance will not cause widespread cascading of the interconnected network.

Single Contingencies

Each branch within OVEC or the systems of OVEC's immediate neighbors (AEP, Cinergy, Dayton, and LGEE).
Each OVEC tieline,
Each Dayton tieline

The OVEC (and DOE-owned stations within the OVEC Balancing Authority area) are primarily of the "breaker and a half" configuration. Therefore, single contingencies can generally be represented by individually removing each branch or generator represented in the powerflow model. Exceptions from this statement include the following:

- Clifty Creek 345/138 kV transformation – The in-service Clifty Creek transformer T-100A does not have automatic switching between the transformer and the 138 kV bus. Forced outages of this transformer also de-energize the Clifty Creek 138 kV bus, opening the ties to Carrolton(E.On), Northside(E.On) and Miami Fort(DEM) until the transformer low-side disconnect can be manually opened and the bus restored.

- Dearborn(OVEC)-Tanners Creek(AEP) 345 kV bus extension – The in-service 345 kV tie between these adjacent OVEC and AEP stations is protected as a bus extension rather than a transmission line. Normal clearing of a fault on the tie or the #1 Tanners Creek bus will also trap the Tanners Creek (AEP) – East Bend (DEM) tie, as well as the Dearborn-Clifty Creek #1 and Dearborn – Pierce circuits.

- The OVEC/IKEC generators are cross-compound machines. Future modeling refinements to increase compatibility between steady state and dynamics models, will have each shaft represented individually. Representing a change in dispatch or status of a single unit will require changes to both HP and LP machines in the model. Furthermore, installation of FGD systems planned at both Clifty Creek and Kyger Creek plants will create the possibility of some common-mode FGD equipment trips that would remove up to 3 units at each plant. Therefore, simulating single generator contingencies should include both single units (both shafts) and 3 units.

Multiple Contingencies

All combinations of branches connected to any OVEC bus, or two layers out from any OVEC bus, augmented by any branches identified in the Single Contingency analysis above. Similar to the discussion in the Single contingency section, the “breaker and a half” configuration present at most OVEC stations means that (neglecting, for screening purposes, the manual system adjustments allowed between the individual “Category B” contingencies in NERC Category C3 contingencies) most types of NERC Category C or D contingencies for OVEC studies can be simulated by simply removing individual branches two at a time. NERC Category D contingencies resulting in complete station outages are also regularly tested. Most common power system analysis tools provide options to easily simulate these outages.