OHIO VALLEY ELECTRIC CORPORATION - 2013 FILING

FERC FORM 715 - ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

PART 4 -- TRANSMISSION PLANNING RELIABILITY CRITERIA

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 OVEC/IKEC System is primarily an EHV network, and is entirely part of the Bulk Electric System (BES). The 138 kV facilities in the OVEC/IKEC System are all associated with interconnections to its Sponsors. In addition to those at the 138 kV class, OVEC/IKEC-Sponsor interconnections include EHV facilities. The DOE load was originally served from two 345 kV stations within the Project's boundaries -- owned, operated, and maintained by DOE. One of these stations remains. The OVEC/IKEC System has eleven generating units located at two plants with a total capacity of about 2300 MW. All OVEC/IKEC generation, with the exception of required operating reserves, is made available to the Sponsors.

As a result of the stringent criteria used in its initial system design and predictable load at the DOE facility, it has been unnecessary to regularly carry out extensive facility planning studies for OVEC/IKEC. Various assessments of OVEC/IKEC system performance, however, are made regularly, including those made as part of the Reliability*First* Corporation (RFC) seasonal, near-term and long-term appraisals, and any others needed to demonstrate compliance with NERC Reliability Standards or the requirements of FERC Order 890. In addition, the OVEC/IKEC system performance is assessed as part of system impact studies carried out at the request of independent power producers seeking to connect to the OVEC/IKEC transmission system. In carrying out the future appraisals, system impact studies, or similar transmission studies, OVEC/IKEC relies on the services of the American Electric Power Service Corporation (AEPSC) East Transmission Planning group to conduct these assessments.

Ohio Valley Electric Corporation/Indiana-Kentucky Electric Corporation
Transmission Planning Criteria and Assessment Practices

<u>Introduction</u>

The following sections present an overview of the criteria that OVEC/IKEC uses for planning a reliable transmission system. The first section describes the principles underlying the planning criteria and discusses the planning process. The following three sections provide details of modeling assumptions, performance expectations, and testing criteria, respectively, for

OVEC/IKEC's transmission system. Specific application of these criteria on a case-by-case basis must employ sound engineering judgment. The transmission planner conducting each study should always evaluate these criteria and apply them in such a manner to account for special considerations applicable to the area under study.

1. UNDERLYING PRINCIPLES AND THE PLANNING PROCESS

1.1 Underlying Principles

It is impossible to anticipate or test for all possible conditions that could adversely affect the OVEC/IKEC transmission system because of the large number of individual elements that comprise the system and the fact that power flows and load levels are continually changing. Therefore, the planning criteria and related contingency tests outlined in this report do not represent an exhaustive set of system operating conditions, transfer levels, and specific contingencies; instead, they constitute an effective and practical means to stress the OVEC/IKEC transmission system, testing its ability to survive the entire spectrum of possible contingencies, and identifying potential weaknesses and problems.

The OVEC/IKEC criteria described herein are consistent with: 1) the North American Electric Reliability Council (NERC) Reliability Standards; 2) the Reliability*First* Corporation (RFC) Standards and 3) other external documents. A listing of those external documents is provided in Appendix A. The application of the NERC and RFC criteria to any particular utility system, including OVEC/IKEC, must be adapted to the specific characteristics of that utility. Each utility's transmission system is configured in a way that is specific to the geographic region it serves as well as the electrical facilities that are installed to meet customer requirements. There are also various ways of achieving reliability objectives. Therefore, differences can exist among the specific planning criteria employed by various systems. Compatibility among different systems' criteria and guidelines are achieved, however, by adopting fundamentally sound planning principles and practices.

This report presents an overview of OVEC/IKEC's transmission planning criteria and assessment practices. Specific application of these criteria and practices on a case-by-case basis must employ sound engineering judgment. The transmission planner conducting each study should always evaluate these criteria and apply them in a manner to account for special considerations applicable to the area under study.

Due to inherent uncertainties associated with long range forecasts, new technological developments, equipment costs, and changing social, economic and political conditions, it is prudent to develop long range transmission plans based on a range of assumed scenarios. Sensitivity analysis is also useful in making these judgments. By their very nature, long-range plans must be reevaluated and modified periodically to reflect the persistent changes in the variety of factors that influence future system performance. While current planning criteria are inherently deterministic, qualitative distinctions about the likelihood of various scenarios and contingencies are recognized.

More likely events require higher levels of system performance; lower system performance standards (greater negative impacts) are acceptable for events that are less likely to happen. Deterministic reliability criteria that are sufficiently stringent to ferret out potential system problems may also result in specific design consequences, which are impractical or too expensive in relation to the benefits, realized or the risks mitigated. In these cases, prudent exceptions to the criteria can be made, or other less expensive control schemes employed.

1.2 Planning Process

The planning process provides the focus for establishing an appropriate level of system reliability. It includes assessments of system performance in the current year; near-term; and long-term periods. The process typically begins with a deterministic appraisal of transmission system performance. When such appraisals identify potential problems, detailed studies are conducted to evaluate the severity of the problem and to develop an optimal plan to remove or mitigate the deficiency.

Seasonal assessments, also referred to as operational planning assessments, have a horizon of up to one year. These appraisals verify that the transmission system, as planned and built based on long-term predictions and assumptions, is adequate to meet the actual requirements that emerge for the approaching peak load periods. Delays in transmission reinforcements, and changing power flow patterns or performance expectations also influence the need for short-term appraisals. These appraisals also provide a warning of future system reinforcement needs. Operational planning appraisals are conducted in a manner similar to facility planning appraisals. The major difference is that problems identified in these assessments cannot be corrected by transmission reinforcements due to insufficient lead-time. Therefore, problems identified by these studies are addressed by deriving indices for system operators to monitor system performance and by establishing operating procedures to mitigate transmission problems detected by the operators during real time operations.

Near-term (1 to 5 years) and Long-term (more than 5 years) facility planning appraisals analyze anticipated system conditions within the specified time period. Near-term and Long-term planning of the transmission system allows adequate time to identify emerging trends and anticipated system deficiencies and then to plan and build needed transmission reinforcements, including time for potentially lengthy regulatory approval processes.

In addition, seasonal, near term and long-term appraisal studies, are conducted jointly with neighboring utilities as part of RFC and Eastern Interconnection Reliability Assessment Group (ERAG) agreements. These joint appraisals focus on measuring the strength of the interconnected network and on assuring coordination of facility planning and operational planning efforts. OVEC/IKEC is represented on the teams that conduct these joint appraisals. Where such assessments uncover deficiencies, the problems are referred to the appropriate company or companies to develop solutions as part of their normal planning process.

This document does not directly address regional and interregional appraisal criteria except to note that OVEC/IKEC's criteria comply with those in RFC and NERC Reliability Standards. Also, OVEC/IKEC uses regional and interregional transfer capability measures that are consistent with the NERC definitions, to assess the strength of its transmission system.

2. KEY MODELING ASSUMPTIONS

The computer models used in transmission planning studies necessarily differ widely in dimensions and details to suit the scope of each study. Power flow models are developed to represent system operation during highly stressed periods such as peak load conditions and heavy power transfers that simulate emergency and opportunity power transactions. System dynamics and short circuit computer models are also used, depending on the specific analysis, to complement the power flow models. Using these computer models, transmission system performance is assessed by simulating disturbances to identify system strengths and weaknesses. In general, the following assumptions are used in conducting various types of transmission planning studies.

The OVEC/IKEC system is used primarily by OVEC for bulk power sales of OVEC generated power to the OVEC owners. A single internal load customer, the DOE, is served by off system generation. OVEC/IKEC System active load (MW) forecasts are based on projections developed by the DOE; and are assumed to be the same for typical peak and off-peak study scenarios. DOE loads are projected to be minimal (compared to the original Project capability) for the foreseeable future. Reactive power (MVAR) loads are based on the customer’s calculated power factors for the projected loads and or recent historical data. Power transfer levels modeled in base cases for analysis of the OVEC/IKEC System vary from one study to another depending on the particular focus of the study. The ERAG Multi-Regional Modeling Working Group (MMWG) load flow base cases generally model only committed firm power transfers. Reliability*First* cases, which are derivatives of the MMWG cases, may be modified to include additional recently experienced biases. Base cases used in OVEC/IKEC's studies are derived from these regional models. Additional sensitivity cases may be used to assure that potential system bottlenecks are identified. The sensitivities most commonly studied involve alternative assumptions about the status or operating level of generation at electrically nearby generating plants, and high levels of transfers, used to simulate parallel flow conditions reflecting recent experience.

All of the OVEC/IKEC generating units are generally dispatched, except for those out of service for maintenance, since all or most of their generation is usually required for sales to Sponsors. The modeled generation output of each of OVEC/IKEC’s two power plants is based on the plant’s capacity relative to the total OVEC/IKEC generation capacity.

Base cases model all transmission facilities in service except for known scheduled maintenance, long-term construction outages, or long-term forced outages. These known outages are normally only reflected in operational planning studies. Because it is impractical and unnecessary to represent all interconnected systems in detail, the type of planning study dictates the extent of the interconnected network representation. Thus, an interconnection study involving the bulk transfer of power between two power systems not only would require sufficient detail of the bulk transmission in each participating system, but also would include sufficient detail and/or equivalent representation of other interconnected systems to assure proper analysis of critical elements.

Sufficient modeling of neighboring systems is essential in any study of the OVEC/IKEC transmission system. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the ERAG MMWG load flow library, or the Sponsors themselves. Sufficient detail is retained to simulate all outages and changes in generation dispatch that are contemplated in the particular study.

With the power flow base cases described above, the study engineer develops scenarios, which are surrogates for a wide range of possible conditions. Numerous facility outages and power transfers occur daily in the interconnected network. It would be impractical to simulate all such possible conditions in planning studies. To establish a manageable set of base case scenarios, historical data and experience are employed. Although history is not a perfect indicator of the future, it provides valuable information to benchmark the base case models. For future power flow base cases, further adjustments are made to reflect forecasted load levels, expected facility changes, and projected power transfers, as well as emerging trends that will affect historical power flow patterns.

The power flow models described above are the most frequently used models for transmission planning studies. Transient stability and short circuit studies are also used to evaluate the system performance during and immediately following fault conditions on the transmission system. The network configurations used in the load flow models also provide a starting point for transient stability and short circuit studies. In addition, for transient stability studies, additional impedance data and electro-mechanical detail of generators and their controls are included.

3. PERFORMANCE STANDARDS

Performance Standards establish the basis for determining whether system response to contingency analysis is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit.

In general, system response to contingencies evolves over a period of several seconds or more. Steady state conditions can be simulated using a power 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 devices such as 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 power 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 OVEC/IKEC System, thermal performance standards are usually the most constraining measure of reliable system performance. Each type of performance standard is described in the following discussion.

3.1 Thermal Limits

Thermal ratings define transmission facility loading limits. Normal ratings are generally based upon no abnormal loss of facility life or equipment damage. Emergency ratings accept some loss of life or strength, over a defined time limit for operation at the rated loading level. The thermal rating for a transmission line is defined by the most limiting condition, be it 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 power flow simulations normally assume all breakers are in service.

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 loading is adjusted for the voltage deviation from nominal to permit an appropriate comparison to the MVA rating.

3.2 Voltage Limits

Voltages at transmission stations should be above the values listed in Table 1 in subsection 4.1 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. Post-contingency voltage drop limits are utilized to prevent voltage instability, which could result in system voltage collapse. OVEC will investigate any potential voltage drop that exceeds 6% for voltage instability. Voltage drops exceeding 10% are considered violations of OVEC's criteria and should be avoided.

3.3 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, as well as longer-term 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. BES facilities are designed to comply with NERC Reliability Standard PRC-023 requirements.

3.5 Short Circuit Limits

Short circuit limits are also an important aspect of system performance, since the extremely high, short duration currents that accompany system faults will impose considerable stresses on network elements. Circuit breakers must be capable of interrupting the anticipated fault currents in the shortest possible time. Failure to interrupt these currents may lead to catastrophic equipment damage and endanger human life. Short circuit levels increase as network reinforcements are implemented or new generating units are added to the system. Therefore, short circuit levels must be reviewed periodically so that inadequate equipment can be replaced or upgraded, or a mitigation procedure developed.

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. In the OVEC/IKEC transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance. Each type of performance requirement is described in the following discussion. Table 1 below documents the performance criteria for all transmission facilities under normal and contingency conditions.

Table 1
OVEC/IKEC Transmission Planning Criteria
(Steady State System Performance)

Transmission System Condition	Maximum Facility Loading (Rating)	Minimum Bus Voltage (Delta V < 10%)	
		EHV	138 kV
All facilities in service (NERC Category A)	Normal	95%	95%
One facility out of service (NERC Categories B1, B2, B3)*	Emergency	93%	92%
Two facilities out of service (NERC Categories C1, C2, C3, C5)* & D**	Emergency	93%	92%

*Categories B4 & C4 involve DC facilities, there are none significant to OVEC performance at this time
** Because the OVEC stations are primarily of “breaker and ½” configuration, steady state simulation of most Category D contingencies is identical to one or more Category C contingencies. Where different, performance is reviewed for risks and consequences. Issues identified may not require mitigation, but may be used to evaluate possible solutions to violations from Category B or C contingencies.

4.1.1 <u>Single and Double Contingencies</u>

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.

4.2 Stability Testing Criteria

The Appendix B Stability Disturbance Testing Criteria specify the disturbance events for which stable operation is required of all BES connected generation, including renewable generation.
The disturbance events specified in testing criteria A through E of Appendix B are applicable to planning and operational planning studies. These disturbance events correspond to the NERC Category B2, B3, C3, C7 and C8 contingencies listed in Table 1 of NERC TPL standards 001 through 004. The disturbance events specified in criteria F and G of Appendix B may also be applied in operational planning studies when a long-term facility outage is anticipated. Testing with disturbance events other than those specified in Appendix B may be performed in planning and operational planning studies where applicable. Examples of such testing include common-failure mode disturbances such as double circuit tower faults (NERC Category C5) or bus faults (NERC Category C9) that result in the outage of multiple facilities at a location. On the AEP

transmission system, NERC Category C1, C2, and C9 contingencies are generally either of the same or less severity than the A criterion (Appendix B) breaker failure events that result in tripping the same facilities.

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.

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.