Transmission System SQRA Assessment Methods

Reliability Metrics for Transmission Systems

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PRODUCT DESCRIPTION

Market conditions and increasingly stringent regulatory requirements have focused attention on metrics that quantify the Security, Quality, Reliability, and Availability (SQRA) of transmission systems. This report summarizes the state-of-the-art in performance metrics, provides four case studies of their use, and discusses future trends in reliability metrics, congestion metrics, and benchmarking.

Results and Findings

The report provides a comprehensive taxonomy of SQRA metrics, including measures of reliability and economic performance as well as a newly developed blended metric designed to efficiently screen large sets of alternative projects for regional planning entities. Reliability metrics are comprised of deterministic and probabilistic metrics as well as of compliance metrics, a new group of metrics that have been developed for tracking compliance with the standards developed by NERC and FERC. The economic metrics include many ways of measuring congestion along with more general performance measures. The description of each metric includes the data inputs needed to calculate the metric, discusses issues related to implementation, and lists the metric's applications. Four case studies show how the operators of large transmission systems are currently using the available metrics for operational and planning purposes and to meet regulatory requirements.

The report reviews current industry initiatives in transmission reliability metrics and several new conceptual approaches currently under consideration to improve the management of the security, quality, reliability, and availability of transmission systems. Significant trends include the expanded use of hybrid metrics and benchmarking and continuing efforts to standardize data and methodology.

Challenges and Objectives

Exceptional forces are changing the use of the transmission infrastructure in the United States and requiring ever-increasing SQRA in a capital-constrained electric power delivery environment. Transmission owners are under increasing scrutiny to plan and operate the system in a manner that ensures compliance with applicable standards created by NERC and approved by FERC. Proper utilization of leading indicator reliability metrics will be ***key*** to ensuring that transmission owners, operators, and planners are compliant with these standards. As part of a larger project to provide senior utility executives with the knowledge, insights, and collaborative resources they need to make informed decisions about transmission system performance, this report documents the state-of-the-art in transmission performance metrics.

Applications, Values, and Use

Exceptional forces are changing the use of the transmission infrastructure in the United States. There are high expectations that the transmission system will support and enable national-level economic, renewable energy, and other emerging policy goals. A large amount of transmission investment is expected, and this investment is largely intended to enable the transmission grid to efficiently perform functions for which it was not originally designed. Reliability metrics will inevitably be a large driver of these investments, and these metrics will be different than those used in the past. This report provides a comprehensive guide to the metrics available and in development to quantify the reliability and economic performance of transmission systems.

EPRI Perspective

The crystal ball is cloudy when it comes to the future of transmission reliability metrics. However, it is clear that there are two ultimate issues of primary concern. These are (1) the price that end users pay for electricity, and (2) the reliability seen by end users. Focusing on end users serves as a guiding compass through the forest of measurement methodologies when deciding the best course to pursue with respect to transmission reliability metrics.

Approach

The project team summarized the metrics currently in use to measure the reliability and economic performance of electric transmission systems. The team developed four case studies on the use of these metrics and explored future trends in reliability metrics, congestion metrics, and benchmarking.

Keywords

Transmission systems
Security, Quality, Reliability, and Availability (SQRA)
Performance measures
Congestion

EXECUTIVE SUMMARY

This scope of work is part of the EPRI project P001.004, "Measurement and Management of Security, Quality, Reliability, and Availability (SQRA)." The overall goal of this project is to provide senior executives with the knowledge, insights, and collaborative resources they need to make informed decisions about transmission system performance when responding to the following:

- Industry changes that mandate heightened SQRA (such as North American Electric Reliability Corporation—NERC rules and the Electric Reliability Organization—ERO),
- Challenges to providing ever-increasing SQRA in today's capital-constrained electric power delivery environment.

The specific goal of this report is to document the state-of-the-art in transmission performance metrics for the purposes of improved management of these systems and for responding to new and future NERC and other regulatory oversight. There are three main sections of this report.

Section 2: Transmission performance metrics. This section will discuss common and emerging performance metrics presently used in the industry. This will include deterministic metrics (e.g., N-1), probabilistic metrics (e.g., expected energy not served), regulatory criteria (e.g., NERC), and economic criteria (e.g., congestion cost). In addition to definitions, this section will discuss the strengths and weaknesses of each metric, data requirements for calculation, and critical interrelationships (e.g., the impact of meeting deterministic criteria on congestion cost). This section will also include a discussion of implementation issues and areas for application.

Section 3: Case Studies. This section will describe at least two case studies that provide insight on issues related to transmission performance metrics, their application, and benchmarking.

Section 4: Future Trends. This section will discuss trends in transmission reliability metrics so that utilities can anticipate what may be coming in future years. This will include a treatment of industry activities in transmission reliability metrics and discusses ideas for thought-leading utilities to consider to best manage the security, quality, reliability, and availability of their transmission systems. This section will also discuss expanding the information necessary for benchmarking.

CONTENTS

1
INTRODUCTION

Exceptional forces are changing the use of the transmission infrastructure in the United States. Customers, regulators, generators, and others expect that the transmission system will support and enable national-level economic, renewable energy, and other emerging policy issues.

The U.S. transmission system was developed in a piecemeal fashion. Originally, transmission systems connected large generation facilities in remote areas to users of the electricity they produced. Shortly thereafter, interconnections with neighbors were developed to enhance reliability and to get access to lower-cost energy. Subsequent transmission lines were typically added incrementally to the network, in a process primarily driven by the needs of the local utility and without wide-area planning considerations.

Opportunistic usage of the transmission system beyond its original design occurred early in the U.S. electric system. The need for coordinated transmission planning among utilities soon followed. As early as 1925, small power pools formed to take advantage of the economies of developing larger, more cost-effective power plants that were made possible by the expanding transmission network.

Today, the transmission system is increasingly being called upon to serve as the platform that enables sophisticated and complex energy and financial transactions. These same market systems have the ability to enable transactions to be interconnection-wide, spanning as much as half of North America.

In addition to expanded usage, regulatory oversight of the planning and operation of the US electric grid is increasing. Transmission owners in the United States are under increasing scrutiny to plan and operate the system in a manner that ensures compliance with applicable standards created by NERC and approved by FERC. Proper utilization of leading indicator reliability metrics will be ***key*** to ensuring that transmission owners, operators and planners are compliant with applicable standards.

This report, developed as part of EPRI Project Number P001.004, summarizes existing metrics in use today that address this changing climate, provides four case studies of their use, and discusses future trends in the reliability metrics, congestion metrics, and benchmarking.

2
EXISTING TRANSMISSION RELIABILITY AND ECONOMIC METRICS

There is a different set of indices to quantify transmission reliability. To date, transmission reliability has been difficult to assess as not all outages of transmission elements result in a loss of service to end use customers. Despite this challenge, various metrics have emerged that measure the performance of the transmission system. This section summarizes different reliability and economic metrics that have been developed and used by different industry and regulatory agencies.

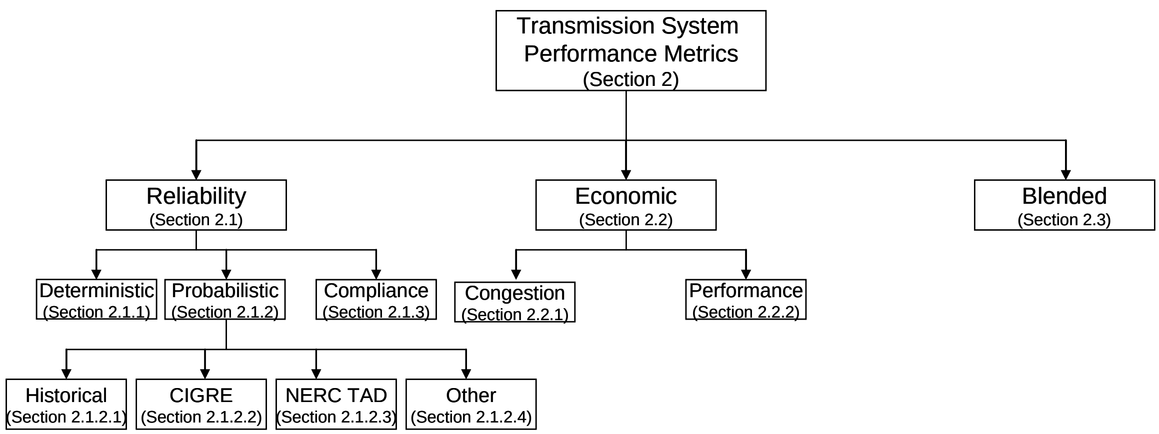

Figure 2-1
Categorization of Transmission Performance Metrics Reviewed in this Document

As shown in Figure 2-1, the metrics that have evolved can be evaluated from three major aspects. These metrics are: general reliability of the system, economic performance, and blended performance, which constitutes both economic and reliability issues along with planning processes.

The reliability metrics are further classified as deterministic, probabilistic, and compliance metrics and are discussed in Section 2.1.

Economic metrics in Section 2.2 provide market-related indices to judge the economic performance of the system. These economic metrics are further classified as congestion and performance-related metrics.

Blended indices in Section 2.3 provide an overview of the emerging metrics that may assist in assessing the performance of the system in a short- or long-term planning horizon. These metrics are meant for the planners for future decision making.

2.1 Reliability Metrics

This section summarizes different reliability criteria that have been used by different industry and regulatory agencies. The reliability of a transmission system can be subdivided into three categories. These are deterministic criteria, probabilistic criteria, and compliance criteria. Deterministic metrics are used to quantify the reliable operation of the transmission network. These metrics provide an indication that the system is being planned and operated such that continuity of service is maintained.

Probabilistic metrics are used to quantify performance when continuity of service is interrupted. Typically derived from similar distribution metrics, they are used to track how the transmission system impacts the end-use customers of electricity.

Compliance metrics are a new group of metrics that have been developed for tracking compliance with the standards developed by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC). As of June 4, 2007, compliance with FERC approved standards is mandatory, with non-compliance subject to monetary penalties.

2.1.1 Deterministic Metrics

The Bulk Electric System is designed such that loss of a line will not result in an outage to end-use customers of the North American electric system. Historically, most bulk-power reliability measures have focused on deterministic contingency criteria related to "system reliability." System reliability is defined as the ability of a power system to supply all of its loads in the event of one or more contingencies (a contingency is an unexpected event such as a system fault or a component outage). This is divided into two separate areas: static security assessment and dynamic security assessment.

Static security assessment determines whether a power system is able to supply peak demand after one or more pieces of equipment (such as a line or a transformer) are disconnected. The system is tested by removing a piece (or multiple pieces) of equipment from the normal power flow model, re-running the power flow, and determining if all bus voltages are acceptable and all pieces of equipment are loaded below emergency ratings. If an unacceptable voltage or overload violation occurs, load must be shed for this condition and the system is *insecure*. If removing any single component will not result in the loss of load, the system is *N-1 Secure*. If removing any *X* arbitrary components will not result in the loss of load, the system is *N-X Secure*. *N* refers to the number of components on the system and *X* refers to the number of components that can be safely removed.

Static security assessment is based on steady-state power flow solutions. For each contingency, it assumes that the system protection has properly operated and the system has reached a steady state. In fact, the power system may not actually reach a steady state after it has been disturbed. Checking whether a system will reach a steady state after a fault occurs is referred to as *dynamic security assessment.*

When a fault occurs, the system is less able to transfer power from synchronous generators to synchronous motors. Since the instantaneous power input has not changed, generators will begin to speed up and motors will begin to slow down. This increases the rotor angle difference between generators and motors. If this rotor angle exceeds a critical value, the system will become unstable and the machines will not be able to regain synchronism. After the protection system clears the fault, the rotor angle difference will still increase because the power transfer limits of the system are still less than the pre-fault condition. If the fault is cleared quickly enough, this additional increase will not cause the rotor angle difference to exceed the critical angle, and the system will return to a synchronous state. Performing a dynamic security assessment is very computationally intensive when compared to performing a static security assessment. The following is the list of deterministic metrics to assess the system reliability.

List of Deterministic Metrics

- N-1 Secured
- N-1-1 Secured
- N-2 Secured

N-1 Secured

Description

If any one element of the system can be removed from the system due to forced outages without jeopardizing the stability and reliability of the system, then the system is said to be N-1 secure. This index is a Boolean index; a system can be either N-1 secured or not N-1 secured.

Data Inputs

System topology, magnitude/geographic distribution of system load, transactions, generation profiles, pre-defined contingency set. Once collected, power flow and contingency analysis runs may be performed to analyze the system for all N-1 contingencies.

Implementation Issues

NERC and FERC regulations make it mandatory to comply with an N-1 reliability standard. N-1 reliability is an indication that the system can withstand one element outage at a time at any given system load.

During the actual operation of the system, conditions can occur that were not envisioned in the planning environment. Therefore, system operators will periodically run contingency analyses throughout the day to track this condition.

In addition, the N-1 secured state presumes the system is operated intact. Transmission systems are rarely operated in this condition. Almost everyday, elements are out of service for a variety of reasons including equipment failure, maintenance, system reconfiguration, provision of clearances, etc. To address this condition the N-1-1 Secured metric was established.

Application

- Planning criteria
- Operations criteria
- Regional Reliability Organizations (RRO)/NERC reporting
- Management metric for tracking system performance (i.e., percent of time in N-1 State for a given day, week, month, year, etc.)
- Regulatory metric for tracking system performance (i.e., percent of time in N-1 State for a given day, week, month, year, etc.)
- Project justification

N-1-1 Secured

Description

If one element can be removed from the system for planned maintenance or other reasons and one element can still be removed from the system due to forced outage without affecting the stability or reliability of the system, then the system is called N-1-1 secured. This index is a Boolean index; a system can be either N-1-1 secured or not N-1-1 secured.

Data Inputs

System topology, magnitude/geographic distribution of system load, transactions, generation profiles, pre-defined contingency set, maintenance schedules, and generator dispatch merit order. Once collected, power flow and contingency analysis runs may be performed to analyze the system for all N-1 contingencies.

Implementation Issues

N-1-1 security is more difficult to assess than N-1 security. The problem with its calculation is how to identify the planned outage elements *a priori*. Analysis is not the same as N-2, which is simultaneous loss of two elements. For this analysis, the first element is taken out of service, then the system is redispatched or reconfigured to ensure the system is in a state that can service the loss of any one additional element.

Maintenance schedules are typically needed to calculate this metric. System planners will need long-range maintenance schedules in order to effectively track this metric. If schedules are not available, system planners will need to coordinate with operations planners on protocols used for scheduling maintenance on key facilities.

Applications

- Planning criteria
- Operations criteria
- RRO/NERC reporting
- Management metric for tracking system performance (i.e., percent of time in N-1-1 State for a given day, week, month, year, etc.)
- Regulatory metric for tracking system performance (i.e., percent of time in N-1-1 State for a given day, week, month, year, etc.)
- Project justification

N-2 Secured

Description

If two elements can be removed simultaneously from the system without affecting the stability and reliability of the system, then the system is called N-2 secured. This index is a Boolean index; a system can be either N-2 secured or not N-2 secured.

Data Inputs

System topology, magnitude/geographic distribution of system load, transactions, generation profiles, pre-defined contingency set. Once collected, power flow and contingency analysis runs may be performed to analyze the system for all N-1 contingencies.

Implementation Issues

If all combinations of N-2 contingencies are run, then computing the metric is computation intensive for large systems.

It should be noted that NERC TPL-003-0 does not require that all combinations must be analyzed. Instead, NERC TPL-003 indicates that N-2 combinations that "produce the more severe system results or impacts" should be studied. Further, TPL-003-0 specifically states that the rationale for contingency selection shall be documented.

Common practice is to investigate situations such as common corridor, common structure, bus outages, etc. In addition, transmission operators are encouraged to critically evaluate other conditions which could result in severe system impacts. One suggestion is to study the simultaneous loss of each element at the highest voltage on the system along with every other single contingency that could exist. Operations planners may also have insight based upon previous operating situations encountered.

Application

- Planning criteria
- Operations criteria
- RRO/NERC reporting
- Management metric for tracking system performance (i.e., percent of time in N-2 State for a given day, week, month, year, etc.)
- Regulatory metric for tracking system performance (i.e., percent of time in N-2 State for a given day, week, month, year, etc.)
- Project justification

2.1.2 Probabilistic Metrics

Contingency criteria are often criticized since they do not consider the probability of a contingency occurring or its impact should it occur. Probabilistic criteria such as Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS) address these concerns. However, they primarily focus on the generation system rather than the transmission system. This type of analysis is often referred to as system adequacy analysis. In some literature [1 – 4], these probabilistic criteria have been used to define metrics for transmission systems as well, assuming that the capacity of generation is sufficient to supply the load.

System adequacy is defined as the ability of a system to supply all of the power demanded by its customers. Three conditions must be met to ensure system adequacy. First, its available generation capacity must be greater than the demanded load plus system losses. Second, it must be able to transport this power to its customers without overloading any equipment. Third, it must serve its loads within acceptable voltage levels.

System adequacy assessment is probabilistic in nature. Each component of the system has a probability of being available, a probability of being available with a reduced capacity, and a probability of being unavailable. To assess the transmission reliability, it is assumed that the generation is sufficient and the distribution systems serving the loads are operated appropriately. This allows the probability of all transmission state combinations to be computed. The availability states of a transmission component can be divided into two main categories and many sub-categories according to [5]. This is shown in Figure 2-2.

An adequacy assessment produces the following information for each load bus: (1) the combinations of generation and loading that result in load interruptions, and (2) the probability of being in each of these inadequate state combinations. From this information, it is simple to compute the expected number of interruptions for each load bus, the expected number of interruption minutes for each load bus, and the expected amount of unserved energy for each load bus. These load bus results can then be aggregated to produce system indices.

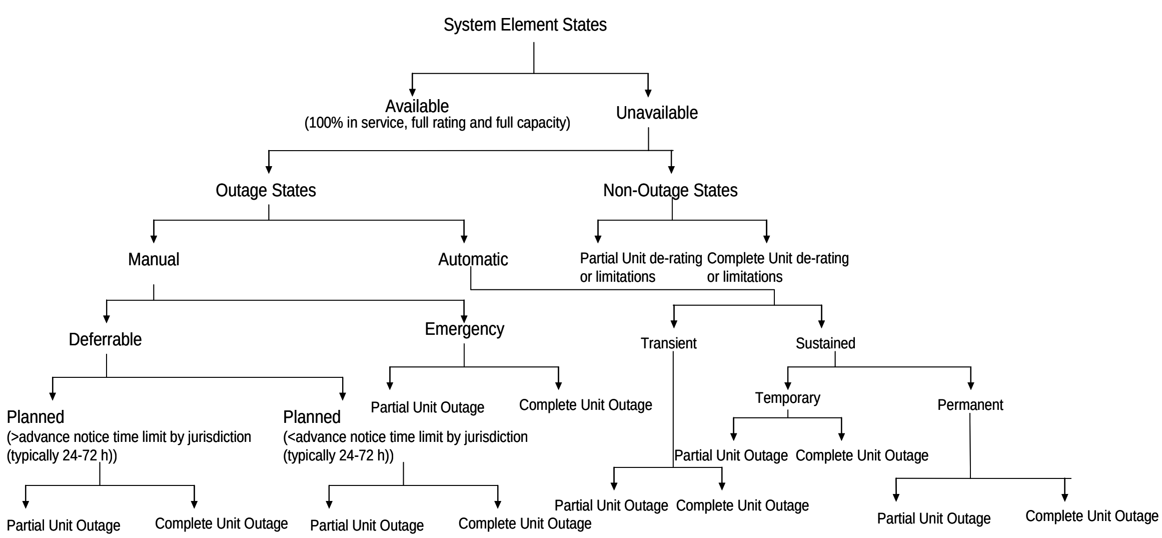

Figure 2-2
System States

System adequacy assessment assumes that the transmission system is available, which by definition does not consider transmission system reliability. It is possible to include transmission system contingencies in the state enumeration process, but since (1) transmission systems are typically N-1 secure, and (2) there are a large number of transmission system components, such an analysis is only feasible on very small systems. Even if such an analysis is done, it represents the reliability of the bulk power system (generation plus transmission) rather than the reliability of the transmission system alone.

The general approach to probabilistic transmission reliability analysis is to assume that all generation is available and to simulate second-order contingencies on an N-1 system. Any interrupted load associated with a contingency is aggregated into an EENS due to the transmission system. However, this is a bit of a misnomer since interrupted transmission load points do not necessarily result in end-customer unserved energy. In addition, it is not clear how to handle situations where equipment is heavily overloaded and/or voltage violations exist (when should load be shed?).

At present, there is no industry standard relating to probabilistic reliability measures of transmission systems. In recent years, several attempts have been made to find different metrics for reliability of transmission systems. Some reviews of these different metrics are given in the following sections, organized by how they are used. Other reliability indices that are most common to the power industry and regulatory boards are also included [8 – 10].

2.1.2.1 Historical Probability Metrics

Though the basic definition for all the four indices is centered on generation availability, but it can also be used similarly for the transmission system. The historical use of LOLE, LOLP, EPNS and EENS are projected values of expectation and probability that the available generation would be less than the load. A low value of these indices would suggest that the system is strong enough to withstand most foreseeable outages, contingencies and peak loads. For transmission system, the unavailability of the source would be due to unavailability of the transfer elements to support the transfer of power from source to load.

List of Historical Probability Metrics

- Loss of Load Expectation (LOLE)
- Expected Energy at Risk (EEAR)
- Expected Energy Not Served (EENS)
- Loss of Load Probability (LOLP)
- Expected Power Not Supplied (EPNS)

Some of these indices are interlinked. The relationship between the derived indices is as follows:

$$LOLE = LOLP * T$$

$$EENS = EPNS * T$$

Here, T is the total time of interruptions.

Loss of Load Expectation (LOLE)

Description

LOLE is the expected average number of hours per year that the system will have to shed load. This is a probabilistic metric. This metric is commonly used to evaluate the adequacy of the system in terms of generation. The LOLE is usually measured in days/year or hours/year. The convention is that when given in days/year, it represents a comparison between daily peak load and available generation. This analysis is typically performed for several years into the future. For transmission-related LOLE calculation, the generation is assumed to be sufficient and the LOLE is calculated according to the availability of the transmission system to transfer the required amount of energy to the loads.

$$LOLE = LOLP * T$$

LOLP is the loss of load probability, and T is the total interruption time.

Data Inputs

The daily or hourly load data for many years, transmission availability data, power flow data, transmission-capacity available transfer capability (ATC), and total transfer capability (TTC) data. Special software is typically purchased to calculate LOLE.

Implementation Issues

The calculation of LOLE for the transmission system is difficult because the loss of load can be due to inadequate generation or due to unavailable transfer capacity in the transmission system. Hence, care should be taken to identify the generation adequacy and transmission system adequacy while calculating transmission-system-related LOLE.

Applications

- Planning criteria
- Project justification
- Regulatory metric for tracking transmission performance for supporting system load

Loss of Load Probability (LOLP)

Description

LOLP is defined as the probability of the days or hours per year or events per season that available generation capacity is insufficient to serve the daily peak load or hourly demand. The basic definition is a metric for generation adequacy. In terms of transmission-system-related LOLP calculation, the daily or hourly probability would be determined according to the availability of the transmission system to supply load. In other words, this is a probability of the days or hours per year that the load can not be supplied due to insufficient transfer capacity of the transmission network.

Data Inputs

The daily or hourly load data for many years, transmission availability data, power flow data, transmission-capacity ATC and TTC data.

Implementation Issues

The calculation of LOLP for the transmission system is difficult because the loss of load can be due to inadequate generation or due to unavailable transfer capacity in the transmission system. Hence, care should be taken to identify the generation adequacy and transmission system adequacy while calculating transmission-system-related LOLP. In addition, all the transmission element outages may not translate into a loss of load. So, there is a need to identify the loss of load which is due to transmission-related outages or unavailable transfer capacity of transmission network. Only events that are associated with transmission element outages or constraints should be included in this calculation. Generation and distribution initiated events should be excluded. If multiple events in transmission, generation, and distribution are associated with the outage, then that may be included as a transmission-related outage.

Applications

- Planning criteria
- Project justification
- Regulatory metric for tracking transmission performance for supporting system load

Expected Energy at Risk (EEAR)

Description

EEAR is an estimate of the percentage of consumer demand for the electric power that is "at risk" of not being served due to weaknesses in the topology, equipment, or contingencies. This is the portion of the annual energy consumer demand that may not be made available to consumers because the power system can not deliver it to the end customer. EEAR is derived from the load duration curve (LDC). Considering a network with N-1 redundancy, EEAR is represented by the area of the LDC curve above the N-1 firm limit line. EEAR can be utilized to calculate Expected Energy Not Served (EENS) for different contingency states. The relation of EEAR and EENS can be given as

$$EENS_{total} = \sum_{i=1}^{N} EEAR_i * P_i$$

where, i is number of outage states and P_i is the probability of the outage states. This outage state can be N-1, N-2, etc. EEAR due to constraints and unavailability of transmission system is to be accounted for when calculating EEAR for transmission system. Energy can be "at risk" if (1) the demand exceeds the rating of the power system component or (2) energy is not expected to be served due to the failure of a power system component.

Data Inputs

The daily or hourly load data for many years, transmission availability data, power flow data, transmission-capacity ATC and TTC data, and load duration data. This index calculation also requires the firm commitment limits for each of the contingent states. The probability of element outage and duration for each contingent state are also required. The equipment ratings in series from the supply point to the delivery point and their probability of failures need to be incorporated in the calculation of EEAR.

Implementation Issues

The calculation of EEAR needs a load duration curve (LDC). This index calculation requires each contingency state to be evaluated using power flow methods; hence EEAR calculation can be very computation intensive. EEAR does not necessarily represent the energy that is at risk, but it helps to calculate EENS for different contingency states. EENS is a weighted summation of the EEAR for each contingent state. The expected energy not served (EENS) can be calculated for multiple contingencies considering the EEAR for different contingency levels. The total EENS will be the sum of all EENS calculated from EEAR of each contingency level. EEAR may not reflect the operational condition of a customer even though the customer may be "at risk" for outage of a certain component in the transmission network. The utility may choose to operate the component at its emergency level or can switch the customer load to another set of equipment. The important advantage of an EEAR index is that it includes the power system configuration, equipment, and load duration curve. In addition, EEAR is calculated considering the equipment rating and transfer capabilities. Hence, it can be useful when evaluating a situation where connectivity to the end customer remains but the system runs out of capability to transfer the energy.

Applications

- Planning criteria
- Project justification

Expected Energy Not Served (EENS)

Description

EENS is the expected number of megawatt hours per year that a system is not able to supply the load. This is a probabilistic metric widely used for generation adequacy. For a transmission system, EENS can be defined as the expected average number of megawatt hours per year that a system is not able to supply the load due to transmission outage or insufficient transmission capacity.

Data Inputs

Power flow data, loss of load probability or expectation (LOLP), and megawatt load data that needs to be shed.

Implementation Issues

As the basic definition of calculating EENS is developed for measuring generation adequacy, it is difficult to appropriately use for the transmission system. Not every transmission element outage translates into load shedding. Also, there can be overlap of insufficient generation and transfer capacity violations or transmission element outages. Hence, care should be taken to identify the load shedding which is a result of only transmission system unavailability or insufficient capacity of transmission system to support the energy transfer. Generation and distribution initiated events should be excluded. If multiple events in transmission, generation, and distribution are associated with the outage, then that may be included as a transmission-related outage. Most of the transmission system follows N-1 reliability criteria and, hence, any one element outage would not initiate loss of load. But, some of the line outages may prompt a generation re-dispatch which can result in load being shed.

Applications

- Planning criteria
- Project justification
- Quantification of societal value (increased energy served)
- Economic justification of transmission (increased energy revenue)
- Regulatory metric for tracking transmission performance for supporting system load

Expected Power Not Supplied (EPNS)

Description

EPNS is the expected number of megawatt loads per year that a system is not able to supply. This is a probabilistic metric widely used for generation adequacy. For a transmission system, EPNS can be defined as the expected number of megawatt load per year that a system is not able to supply due to transmission outage or insufficient transmission capacity. This index is an indication of the amount of the total load in megawatts that may not be served due to inadequate supply over a year.

Data Inputs

Power flow data, loss of load data in megawatts.

Implementation Issues

As the basic definition of calculating EPNS is developed for measuring generation adequacy, it is difficult to appropriately use for the transmission system. Not every transmission element outage translates into load shedding. Also, there can be overlap of insufficient generation and transfer capacity violations or transmission element outages. Only events that are associated with transmission element outages or constraints should be included in these calculations. Generation and distribution initiated events should be excluded. If multiple events in transmission, generation and distribution are associated with the outage, then that may be included as a transmission-related outage. Most of the transmission system follows N-1 reliability criteria and, hence, any one element outage would not initiate loss of load. But, some of the line outages may prompt a generation re-dispatch which can result into load being shed.

Applications

- Planning criteria
- Project justification
- Quantification of societal value (capacity contribution)
- Regulatory metric for tracking transmission performance for supporting system load

2.1.2.2 CIGRE Reliability Metrics

In an earlier report of EPRI [7], a set of HV and EHV transmission and sub-transmission metrics or indices are identified according to International Council on Large Electric Systems (CIGRE) Power Quality Indices and objectives (C4.1.04). These metrics are divided into three main categories as follows:

- Connection point interruption performance indices (CPI)
  - SAIFI-CPI
  - MAIFI-CPI
  - SAIDI-CPI
  - SAIRI-CPI
- End-Customer Load Interruption Indices (CLI)
  - SAIFI-CLI
  - MAIFI-CLI
  - CAIDI
  - SAIDI-CLI
- System Interrupted Energy Performance Indices
  - AIF
  - AID
  - AIT
  - SM

Sustained Average Interruption Frequency Index – Connection Point Index (SAIFI-CPI)

Description

Average frequency of sustained connection point interruptions per year. This index provides the average number of sustained outages at each connection point per year. Its unit is the number of sustained interruptions/year.

Data Inputs

Total number of sustained connection point interruptions and number of connection points for the system.

Implementation Issues

SAIFI-CPI provides average interruption frequency for connection points. However, it may not reflect the actual energy or power that is interrupted due to outages and, therefore, would not be appropriate for quantifying the value of loss revenue. The metric is best used for understanding the impact of transmission (versus distribution) on customer outages.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, the time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Momentary Average Interruption Frequency Index – Connection Point Index (MAIFI-CPI)

Description

Average frequency of momentary connection point interruptions per year. This is the average number of momentary interruptions at each connection point per year. Its unit is the number of momentary interruption/year.

Data Inputs

Number of interruptions for each connection point. Duration of each interruption.

Implementation Issues

MAIFI-CPI provides average interruption frequency for momentary outages at each connection point. But, the definition for momentary and sustained outage varies from system to system. Hence, to use it as a global metric, the momentary interruption definition needs to be consistent over systems. Also, depending on the sensitivity of the equipment, some momentary outages may not be recorded properly.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

Applications

- Regulatory quality of service measure
- System performance tracking
- Comparative analysis of customer interconnections on the system

Sustained Average Interruption Duration Index – Connection Point Index (SAIDI-CPI)

Description

Average total duration of all sustained connection point interruptions per year. Its unit is hours/year or minutes/year.

Data Inputs

Total hours of sustained connection point interruptions and number of connection points for the system.

Implementation Issues

SAIDI-CPI provides average interruption hours for sustained outage at connection points. But, it may not reflect the actual energy or power that is interrupted due to outages. Hence, care should be taken to use the metric for evaluation of system reliability.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Sustained Average Interruption Restoration Index – Connection Point Index (SAIRI-CPI)

Description

Average duration of a sustained connection point interruption during the year. Its unit is hours/year or minutes/year.

Data Inputs

Duration of each interruption and number of connection points.

Implementation Issues

Each utility has different criteria to define sustained and momentary outages. Most of the old equipment may not have a data recorder to record the outage of that element. Hence, it is difficult for utilities to properly accumulate all the interruption records for index calculation. Another issue in calculating the indices is whether planned outages are to be considered for this calculation or not.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Sustained Average Interruption Frequency Index – Connection Load Index (SAIFI-CLI)

Description

Average frequency of sustained customer load interruptions per year. This index provides the average number of sustained outages of customer loads per year. Its unit is number of sustained interruptions/year.

Data Inputs

Total number of sustained customer interruptions and total number of customers.

Implementation Issues

SAIFI-CLI provides average interruption frequency for customer loads. However, it would not reflect the actual energy or power that is interrupted due to outages.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Momentary Average Interruption Frequency Index – Connection Load Index (MAIFI-CLI)

Description

Average frequency of momentary customer load interruptions per year. This is the average number of momentary interruptions of end customer loads per year. Its unit is number of momentary interruption/year.

Data Inputs

Total number of momentary customer load interruptions and total number of customers in the system.

Implementation Issues

MAIFI-CLI provides average interruption frequency for momentary outages at the customer load point. But, the definitions for momentary and sustained outages vary from system to system. Hence, to use it as a global metric, the momentary interruption definition needs to be consistent over systems. Also, depending on the sensitivity of the equipment, some momentary outages may not be recorded properly.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Customer Average Interruption Duration Index (CAIDI)

Description

CAIDI is defined as the average duration of a customer interruption per year. Its unit is minutes.

Data Inputs

Duration of each momentary customer interruption and the number of customers in the system.

Implementation Issues

CAIDI provides average interruption hours for automatic outages for customers. This index does not reflect the amount of energy that is not served. Hence, it does not truly provide the customer cost associated with outages.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Sustained Average Interruption Duration Index – Connection Load Index (SAIDI-CLI)

Description

Average total duration of all sustained customer load interruptions per year. Its unit is hours/year or minutes/year.

Data Inputs

Duration of each interruption and total number of customers in the system.

Implementation Issues

Each utility and customer has different criteria to define sustained and momentary outages. Also, depending on the sensitivity of the equipment, some momentary outages may not be recorded properly. Most of the old equipment may not have a data recorder to record the outage of that element. In addition customer interruptions are sometimes difficult to track because of their large number. So, for any outages, it may be hard to know exactly how many customers are out while the restoration process is going on.

Use requires defining a minimum time necessary to constitute a sustained outage. Effective use for evaluating transmission impacts on frequency of customer interruptions requires a time definition that is the same as that used for distribution.

If used for benchmarking with other systems, time definition of a sustained outage must be the same as that used for the benchmarked systems.

Applications

- Regulatory quality of service measure
- System performance tracking

Average Interruption Frequency (AIF)

Description

AIF is defined as the average number of system interruptions per year. Its unit is total number of system interruptions/year.

Data Inputs

Total number of interruptions in the system.

Implementation Issues

AIF provides total number of system interruptions in a system where energy cannot be supplied due to interruption. This provides a more realistic view of the system performance for a given utility.

This metric may not be useful for benchmarking as it does not normalize the interruptions with factors such as system load or number of customer interconnections.

Applications

- Regulatory quality of service measure
- System performance tracking

Average Interruption Duration (AID)

Description

AID is defined as given below:

$$AID = \frac{\sum T\text{-}PNS}{\sum PNS} = \frac{\sum EENS\text{-}SI}{\sum PNS} = \frac{AIT}{AIF} \text{ min/Interruption.}$$

Where, T is the duration of each sustained interruption; PNS is the interrupted power. Hence, this index is a weighted average in function of the interrupted power. EENS-SI is the estimated energy not supplied for each sustained interruption (MWh).

Data Inputs

Duration of each interruption, power not supplied due to each outage. Data input can also be a combination of EENS, PNS, or AIT and AIF.

Implementation Issues

AID provides average number of hours that energy can not be supplied due to an interruption. This provides a more realistic view of the system performance.

Applications

- Regulatory quality of service measure
- System performance tracking

Average Interruption Time (AIT)

Description

AIT is defined as given below:

$$AIT = \frac{8760 * 60 * ENS}{AD}$$

Where ENS is the energy not supplied due to interruptions with network loss excluded (MWh/year) and AD is the annual demand for the power system with network losses excluded (MWh/year). AIT can also be defined as a function of EENS-SI and the yearly energy consumption as follows:

$$AIT = \frac{8760 * 60 * \sum EENS\text{-}SI}{YEC * 10^6}$$

where EENS-SI is the estimated energy not supplied for each interruption (MWh), and YEC is the yearly energy consumption in the system (TWh).

Data Inputs

For each year, total number of interruptions in the system, duration of each interruption, energy not supplied (ENS), and actual demand (AD) is required to calculate this index. A combination of EENS-SI and YEC (yearly consumption of the system) can also be used to calculate AIT for the system.

Implementation Issues

The average number of interruptions and the durations provide a good measure to evaluate the system performance or reliability, but connecting an energy outage to a transmission element outage may be difficult. To ensure the reliability indices truly reflect the system condition, care should be taken to isolate the interruptions due to transmission elements from distribution and generation system unavailability.

Applications

- Regulatory quality of service measure
- System performance tracking

System Minutes (SM)

Description

System minutes is a function of the size of the system and the energy not supplied.

$$\text{System Minute} = \frac{60 * ENS}{PD}$$

where ENS is the total energy not supplied due to interruptions from all incidents (MWh), and PD is the annual peak demand for reporting year (MW). The estimated energy not supplied (ENS) includes transmission-caused events where customer loads were interrupted, shed, or reduced and that are not associated with a connection point interruption.

Data Inputs

For each year, total number of interruptions in the system, duration of each interruption, energy not supplied (ENS), and actual peak demand (PD) is required to calculate this index. It includes momentary events. The calculation of estimated energy not served may be calculated as MW interrupted multiplied by the duration of event. If information is available on stepped restoration, this may be calculated from the summation of each restoration step.

Implementation Issues

All the events of generation and distribution outages need to be excluded from the calculation of system minutes for transmission system. SM provide an indication of the severity of the event. The severity index according to CIGRE is defined based on system minutes. SM<1 for a year is considered acceptable, while for SM>1, there are different degrees of severity from 1 to 3. If SM is between 1 and 9 then degree of severity is 1, for 10 to 99 degree of severity is 2, and for greater than 100, degree of severity is 3. Hence, SM can be used to track the quality of service and system performance over a year.

Applications

- Regulatory quality of service measure
- System performance tracking

2.1.2.3 Reliability Metrics under NERC TAD

North American Electric Reliability Council (NERC) has also defined some static reliability metrics in their recent endeavors towards strengthening the transmission reliability of the system [6]. Details of reliability metrics that NERC recommends to use from the NERC TAD document are given below.

List of NERC Reliability Metrics

- Element Total Automatic Outage Frequency (TOF)
- Element Sustained Outage Frequency (SOF)
- Element Momentary Outage Frequency (MOF)
- Element Sustained Outage Duration Time (SODT)
- Element Sustained Outage Mean Time to Repair (MTTR)
- Mean Time Between Sustained Element Outages (Mean “Up Time”)(MTBF)
- Median Time to Repair Sustained Element Outage Failure (MdTTR)
- Element Availability Percentage (APC)
- Percentage of Elements with Zero Automatic Outages (PCZO)
- Circuit Total Outage Frequency, Mileage Adjusted (TCOF(100CTmi))
- Circuit Sustained Outage Frequency, Mileage Adjusted (SCOF (100CTmi))
- Circuit Momentary Outage Frequency, Mileage Adjusted (MCOF (100CTmi))

Element Total Automatic Outage Frequency (TOF)

Description

TOF is defined as the total automatic outages / total number of elements per year. Its unit is number per year. Automatic outage means unplanned or forced outages which have happened due to automatic operation of system devices like automatic breaker operation.

Data Inputs

Total automatic outages for a year and total number of elements in the system. Total outage includes sustained and momentary outages.

Implementation Issues

TOF alone does not provide proper information as the duration is not included in the metric. Also, outage of any transmission element may not impact the system and customers.

Application

- Maintenance tracking

Element Sustained Outage Frequency (SOF)

<u>Description</u>

SOF is the total sustained outages per year/total elements. Its unit is number/year.

<u>Data Inputs</u>

To calculate SOF, data is needed for each sustained outage and all operating elements in the transmission system over a year.

<u>Implementation Issues</u>

SOF provides information about sustained outages. But, the definition of sustained and momentary varies from system to system. Also, any sustained outage may not impact the system as most of the transmission system is N-1 secure to comply with NERC and FERC regulations.

<u>Application</u>

- Maintenance tracking

Element Momentary Outage Frequency (MOF)

Description

MOF is the total number of momentary outage per year / total number of elements. Its unit is number/year.

Data Inputs

Number of momentary outages each year and the number of total operating elements.

Implementation Issues

Momentary outages can be due to disturbances which may be unavoidable. MOF does not provide the exact information about whether the system component fails or if there is a transient in the system. Comparison of MOF between different systems is very difficult because of geographical differences.

Application

- Maintenance tracking

Element Sustained Outage Duration Time (SODT)

Description

SODT is the total duration of sustained outages per year in hours / total number of elements. Its unit is hours/year.

Data Inputs

Duration of each sustained outage over a year and the number of total operating elements.

Implementation Issues

SODT shows the average duration of sustained outages. But, one transmission element outage does not necessarily jeopardize the reliability of the system as the system is at minimum N-1 secure. Hence, combination of these indices together should be considered to evaluate reliability performance of one system.

Applications

- Operational performance
- Maintenance tracking

Element Sustained Outage Mean Time to Repair (MTTR)

Description

MTTR is defined as the total sustained outage hours per year/ total element outages. Its unit is hours/year.

Data Inputs

Duration of each sustained outage over a year and the number of total operating elements.

Implementation Issues

MTTR can be used as an index for maintenance, because MTTR provides the average hours needed to repair an element.

Applications

- Maintenance
- Efficiency of restoration

Mean Time Between Sustained Element Outages (Mean "Up Time") (MTBF)

Description

(Total element operational hours – total sustained outage hours) / Total elements. Its unit is in hours. This is the average hours of operation of an element before it fails.

Data Inputs

Each element's operating hours, total sustained outages, and total number of elements in the system.

Implementation Issues

This metric can provide a reliability of operation for each element. This gives an idea to the system operators for preemptive maintenance if the operating hours of any element are approaching the MTBF value.

Applications

- Preventative maintenance

Median Time to Repair Sustained Element Outage Failure (MdTTR)

Description

The time when 50% of time to repair minutes are greater than this number. This means that half of the observed values for the repair time are greater than the median value. Its unit is hours.

Data Inputs

Mean time to repair for each element in the system.

Implementation Issues

This metric can provide a measure of the performance of maintenance throughout the system.

Applications

- Maintenance efficiency

Element Availability Percentage (APC)

Description

(1 – Total sustained outage hours / total element hours) * 100. This metric shows the percentage of time the element is available. The unit is percent.

Data Inputs

Total sustained outage hours and total element operating hours.

Implementation Issues

This metric provides information about the availability of the system elements. This can be used to plan maintenance of other elements and assess the reliability of the complete system. The problem with this metric is that availability of the element does not differentiate between complete or partial availability of the elements.

Applications

- Operational performance
- Benchmarking different manufacturers

Percentage of Elements with Zero Automatic Outages (PCZO)

Description

Total elements with zero automatic outages / total elements * 100. The unit is percent.

Data Inputs

Total elements with no automatic outage and total number of operating elements.

Implementation Issues

Because a higher percentage of PCZO can be considered proof of proper maintenance or robust elements, using a PCZO index to measure the reliability of an element can be confusing. Therefore, PCZO should be used with MTTR and MTBF to provide a better picture of the reliability of the system elements.

Applications

- Maintenance programs

Circuit Total Outage Frequency, Mileage Adjusted (TCOF (100CTmi))

Description

Total number of circuit automatic outages per 100 circuit miles per year. Its unit is number of outages/100ct-miles/year.

Data Inputs

Total number of automatic outages over a year and total circuit mileages.

Implementation Issues

This metric provides a measure of TOF considering total circuit mileage. Hence, it is better than using just TOF for comparison between systems. But, TCOF calculation does not consider the geographic location of the elements and hence may not be suitable to compare two system performances located in different climatic regions.

Applications

- System performance
- Maintenance program

Circuit Sustained Outage Frequency, Mileage Adjusted (SCOF (100CTmi))

Description

Total number of sustained circuit outages per 100 miles per year. Its unit is number of sustained outages/100 ct-miles/year.

Data Inputs

Total number of sustained outages per year and total circuit miles.

Implementation Issues

This metric provides a measure of SOF considering total circuit mileage. Hence, it is better than using just SOF for comparison between systems. But, SCOF calculations do not consider the geographic locations of the elements and hence may not be suitable to compare two system performances located in different climatic regions.

Application

- System performance
- Maintenance program

Circuit Momentary Outage Frequency, Mileage Adjusted (MCOF (100CTmi))

Description

Total number of momentary circuit outages per 100 miles per year. Its unit is number of momentary outages/100 ct-miles/year.

Data Inputs

Total number of momentary outages per year and total circuit miles.

Implementation Issues

This metric provides a measure of MOF considering total circuit mileage. Hence, it is better than using just MOF for comparison between systems. But, MCOF calculations do not consider the geographic locations of the elements and hence may not be suitable to compare two system performances located in different climatic regions.

Applications

- System performance
- Maintenance program

2.1.2.4 Other Metrics

In other reports [1 – 4], authors have sighted additional reliability indexes or metrics which can be used to evaluate and compare the performance of transmission systems. Among them, the most widely used are given below.

- System Average Restoration Index (SARI)
- Delivery Point Unreliability Index (DPUI)

System Average Restoration Index (SARI)

Description

Total duration of all interruptions / Total number of sustained interruptions. The unit of SARI is minutes per interruption. SARI represents the average restoration time in minutes for each point of delivery. For transmission-related outages, SARI provides the restoration time for the transmission system.

Data Inputs

Duration of each interruption, total number of interruptions, and total number of sustained interruptions.

Implementation Issues

SARI can provide a measure of how good the maintenance performance of a system is after interruptions. Hence, it is more of an index to show the promptness of maintenance service of a utility.

Applications

- Regulatory quality of service metric
- Efficiency of restoration
- System performance

Delivery Point Unreliability Index (DPUI)

<u>Description</u>

Total unsupplied energy in MW-min / System peak load in MW. The unit is system minutes. One “system minute” is equivalent to an interruption of the total system load for 1 min at the time of system annual peak load. DPUI for transmission elements would be due to failure of transmission elements only.

<u>Data Inputs</u>

Total unsupplied energy in MW-min and system peak load in MW.

<u>Implementation Issues</u>

DPUI provides a measure of unreliability. But system interruptions may not be coincident with the system peak load. Hence, DPUI is a conservative approach of determining reliability of a system.

<u>Applications</u>

- Operational performance
- Regulatory quality of service metric

2.1.3 Compliance Metrics

A variety of metrics can be envisioned for use in evaluating and comparing transmission system performance in the context of applicable NERC standards. Some key metrics for consideration are:

- Total Number of Violations of NERC Standards
- Number of Interconnection Reliability Operating Limits (IROLs) Violations
- Number of System Operating Limits (SOLs) Violations
- Certified Operators / Total Number of Operators

Total Number of Violations of NERC Standards

Description

This metric shows the total violations of NERC Standards. It is a measure of non-compliance with applicable standards. Its unit is number of violations.

Data Inputs

Audit reports, self-certification filings, remediation action plans.

Implementation Issues

The total number of violations can be regarded as a complete picture of the system regarding system reliability. Any number other than 0 indicates exposure to a potential fine from FERC due to non-compliance.

Applications

- Operational risk (high level of violations indicates less focus on following requirements of operating within the Bulk Electric System)
- Regulatory compliance tracking

Number of Interconnection Reliability Operating Limits (IROLs) Violations

Description

This metric is a measure of the total times within a year that the organization violated IROL. Its units are number of violations per year.

Data Inputs

System operations contingency analysis runs, audit reports, self-certification filings, remediation action plans.

Implementation Issues

Violation of an IROL is determined by the governing Reliability Authority. This is typically based on local, regional, and inter-regional studies including seasonal assessments and ad hoc studies. During real time operations, the IROLs are calculated using the NERC Transmission Limit Calculator (TLC). The TLC uses a state estimator to calculate the transfer limits for a voltage collapse. This limit is calculated at certain time intervals depending on the entities.

Applications

- Operational risk (high level of violations indicates less focus on following requirements of operating within the Bulk Electric System)
- Regulatory compliance tracking

Number of System Operating Limits (SOLs) Violations

Description

This metric is a measure of the total times within a year that the organization violated the SOL. Its units are number of violations per year.

Data Inputs

System operations contingency analysis runs, audit reports, self-certification filings, remediation action plans.

Implementation Issues

SOL is mostly driven by the stability limits associated with a list of multiple contingencies. Requirement R1 of FAC-010-1 asks for providing a documentation of SOL methodology in a planning area that is applicable to the planning time horizon, should not exceed facility ratings, and includes a description of the identified subset of SOLs that qualify as interconnection reliability operating limits (IROLs).

Applications

- Operational risk (high level of violations indicates less focus on following requirements of operating within the Bulk Electric System)
- Regulatory compliance tracking

Certified Operators / Total Number of Operators

Description

This metric is a ratio of the number of certified system operators to the number of total system operators.

Data Inputs

Operator certifications, training records.

Implementation Issues

This ratio gives an indication of the staff level of training and ability to handle reliability issues as they arise. A high ratio of certified operators will increase the likelihood of compliance with applicable standards governing operations.

Applications

- Operational risk
- Compliance risk
- Regulatory compliance tracking

2.2 Congestion and Economic Metrics

Transmission congestion occurs when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels, either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. There are many ways to measure transmission congestion, but thus far there is no one metric that captures all important aspects of congestion. This section surveys different congestion and performance metrics related to the magnitude and impact of congestion and the cost of congestion in order to better understand the factors related to congestion explicitly and implicitly, and provide insights on refining current metrics or developing new metrics.

This section begins with a general discussion on the use of congestion and economic metrics for the purposes of determining societal costs.

2.2.1 Challenges of Societal Cost Minimization

It costs money for a utility to improve the reliability of its network. There is also a cost that customers incur when they experience interruptions in their electrical supply. In theory, it is better for society to improve reliability if the money saved by customers due to improved reliability or decreased energy costs exceeds the cost to the utility to achieve the reliability improvement. Societal cost minimization is often used as a driver of utility expenditures.

To effectively utilize minimizing societal cost as a project driver, however, it should be used along with appropriate cost allocation. Consider an industrial factory that experiences large economic costs whenever its electrical supply is interrupted. Now suppose that a perfect economic analysis shows that the factory will save a bit more than one million dollars if the electric utility spends a bit less than one million dollars. From a societal perspective, it appears that the utility should spend the money.

However, if revenues are unchanged, this situation amounts to a transfer of wealth from the owners of the utility to the owners of the factory. If the utility is not compensated in some way, the stock price of the utility will drop, owners of the stock will become less wealthy, and the ability of the utility to attract capital will weaken. The following points provide emphasis of this point.

Issue 1: Without compensation, minimizing societal cost transfers wealth from utility owners to utility customers.

Now assume that "prudent expenses" are allowed in the utility rate base so that investors can attain their expected return on investment. Investors are happy, but the utility will encounter other problems. Consider again the factory on which the utility has now spent one million dollars in reliability improvements. Now consider a competitor's factory that happens to be located on a part of the system where it is expensive to improve reliability. Due to the higher cost to improve reliability, societal cost is minimized by not improving reliability. This leaves the second factory in a situation where it is paying the same rate as its competitor, but receives a smaller amount of utility investment. In effect, the second factory is subsidizing the profits of the first factory.

Issue 2: With an inflexible rate structure, minimizing societal cost creates cross-subsidies from areas with a high cost to improve reliability to areas with a low cost to improve reliability.

In the same way, minimizing societal cost can bias investment towards customers with a high cost of poor reliability. Consider an affluent neighborhood where most residential houses have home computers and have efficient heat pumps. Now consider a poor neighborhood where most residential houses do not have home computers, and have baseboard heating. The total electrical demand for each neighborhood is the same, but the cost of poor reliability for the affluent neighborhood is higher due to the presence of computers and other expensive electronics. By minimizing societal cost, the utility will be required to spend more on the affluent neighborhood, even though all residential rates may be the same.

Issue 3: With an inflexible rate structure, minimizing societal cost creates cross-subsidies from areas with a low cost of poor reliability to areas with a high cost of poor reliability.

Now consider the factory again. It may well be the case that the factory can save itself one million dollars in reliability improvement by spending far less than one million dollars. This could be done through on-site emergency generation, uninterruptible power supplies, load desensitization, and so forth. However, the factory owners would prefer that the utility fix the problem, even though the societal cost is higher. The more confident that the factory owners are that they can get the utility to pay for the improvement, the less likely they are to explore customer-funded alternatives.

Issue 4: When a utility makes decisions by minimizing societal cost, it leads to under investment in customer-funded reliability improvement projects, which defeats the purpose of minimizing societal cost.

The first four issues assume that the customer cost of poor reliability is perfectly known. In reality, the cost of poor reliability is very customer specific, and difficult to ascertain. As a result, customer survey data is of questionable value. This is evidenced by presenting a solution by which the customer will pay for the reliability improvement for an amount that, according to the survey, results in a positive net present value investment. In many cases the “customer pays” solution is rejected as too expensive.

A related problem is gaming. If a customer knows that utility investments are based on survey results, gaming behavior can result in overstating the cost of poor reliability to increase the level of utility reliability investment.

Issue 5: Surveys almost always overstate a customer’s cost of poor reliability when compared to the customer’s willingness to pay for reliability improvements. Further, customer gaming behavior can lead to intentionally overstated responses.

The only practical way to minimize societal cost is to set reasonable reliability standards and make customers pay for all reliability above these minimum standards. The difficulty in having customers pay for reliability improvements is free-riding. That is, reliability improvements paid for by one customer often benefit other customers. Consider a transmission line that serves ten identical factories. When the transmission line experiences an outage, all ten factories are equally affected, and reliability improvements on the transmission line equally benefit all factories. Now assume that all ten of the factories will benefit if $1 million is spent to improve the reliability of the transmission line. Divided equally, each factory will spend $100,000 but will realize

$130,000 in savings. One of the clever factory managers computes that if only nine factories share the cost, each will pay $111,111 but will still receive more in benefits. Therefore, this manager refuses to pay for the project in hopes that the remaining nine will still make a "rational economic decision." All of the other managers realize now that if only eight factories share the cost, each will pay $125,000. At this point, most of the plant managers will simply refuse to pay for the project unless everyone pays his fair share. In the real world, it is difficult to measure the reliability benefit of each customer and the issue of "fair share" is difficult to solve. The end result is typically a perception of free riders, a refusal to pay for free riders, and an underinvestment in reliability.

Of course, one option is to allow a utility to allocate reliability improvement costs to all customers that benefit. This, however, amounts to rate-base design, which is a function of regulatory authorities, not utilities.

2.2.2 List of Congestion Metrics

- Locational Marginal Price (LMP)
- Congestion Cost
- Financial Transmission Rights (FTR)
- Societal Benefits
- Modified Societal Benefits
- Available Transfer Capability (ATC)
- Available Flowgate Capability (AFC)
- Existing Transmission Commitments (ETC)
- Capacity Benefit Margin (CBM)
- Transmission Reliability Margin (TRM)
- Transmission Loading Relief (TLR)
- Weighted Transmission Loading Relief (WTLR)
- ISO Ratepayers Benefit
- ISO Participant Benefit
- All-hours Shadow Price
- Binding Hours Shadow Price
- Congestion Rent
- Change in Production Cost
- Change in Congestion Payments
- Change in Generation Payments
- Change in Load Payments
- Adjusted Production Cost (APC)

Locational Marginal Price (LMP)

Description

LMP is defined as the cost to serve the next megawatt of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits. Equivalently, LMP can be considered as the shadow/opportunity price of the nodal energy balance with respect to nodal load in security-constrained optimal dispatch. LMP is a market-based method for congestion management which provides a simple answer to the complex problem of dispatching generators and setting prices in a system with transmission constraints.

Data Inputs

The expression for LMP at node i is [17][18][20]:

$$LMP_i = LMP_i^{energy} - LMP_i^{loss} + LMP_i^{congestion}$$

LMP_i can be split into three components depending on the choice of reference node:

- *Energy Component* LMP_i^{energy} --- Marginal electricity cost at the reference node ignoring the cost of congestion and losses.
  - Represents optimal dispatch ignoring congestion and losses.
  - Same price for every bus in the system.
  - Used to price Spot Market Interchange.
  - Calculated both in day ahead and real time.
- *Loss Component* LMP_i^{loss} --- Marginal cost for supplying the losses from the accessible marginal generators to the grid point in question which reflects the cost of losses at that node relative to the reference point. There are several available ways to deal with LMP_i^{loss}:
  - Ignoring the marginal loss. If the LMPs reflect marginal losses, the marginal-loss term in the LMP formula can be ignored with a "reasonable" choice of the reference [19].
  - Introducing loss distribution factors to explicitly balance the consumed losses in the lossless DC power system model. This has been deployed by ISO-NE and ALSTOM's T&D Energy Automation and Information Business [16].
  - Applying loss penalty factors PF_i to each and every location i including generation, transmission, and virtual transaction [14].
    - $PF_i = \left(1 - \dfrac{\text{Change in Loss}}{\text{Change in Unit's Output}}\right)^{-1}$
- *Congestion Component* $LMP_i^{congestion}$ --- Cost of out-of-merit dispatch to accommodate the system constraints using more expensive energy.
  - Represents price of congestion for binding constraints
    - Calculated using cost of marginal units controlling constraints and sensitivity factors on each bus

        - No change in this calculation
    - Will be zero if no constraints
    - Will vary by location if system is constrained
    - Used to price explicit and implicit congestion (Locational Net Congestion Bill)
        - Load pays congestion price
        - Generation is paid congestion price
        - Congestion revenues allocated as hourly credits to FTR holders
    - Calculated both in day ahead and real time

Implementation Issues

A 2002 Notice of Public Ruling (NOPR) from Federal Energy Regulatory Commission (FERC) proposed location-based marginal pricing (LMP) together with financial transmission rights (FTR) as a mechanism to build efficient electricity energy markets [13]. LMP is part of the standard market design (SMD) promoted by FERC and is a fundamental principle in the majority of electricity markets [14 -- 16].

A challenge exists with predicting the impact of transmission investment on LMP. Security constrained economic dispatch (SCED) software exists to allow for estimating production cost savings due to alleviation of congestion. However, LMP is a market-based price. Therefore, savings estimates typically require calibrating SCED programs with previous year's data to correlate market impacts with production costs.

Applications

- Quantifying societal benefit
- Project justification
- Quantifying economic performance of transmission operations

Congestion Cost

Description

Congestion cost is the cost of congestion as measured by the difference between the congestion components of the LMPs at different locations. The cost of congestion varies in real time according to changes in the levels and patterns of customers' demand (including their response to price changes), the availability of output from various generation sources, the cost of generation fuels, and the availability of transmission capacity.

Data Inputs

LMPs at locations under consideration.

Implementation Issues

Congestion cost caused by transmission constraints to some degree affects virtually every customer's electricity bill. Although congestion has costs, in many locations those costs are not large enough to justify making the investments needed to alleviate the congestion

A challenge exists with predicting the impact of transmission investment on LMP. Security-constrained economic dispatch (SCED) software exists to allow for estimating production cost savings due to alleviation of congestion. However, LMP is a market-based price. Therefore, savings estimates based upon reducing congestion costs typically require calibrating SCED programs with previous year's data to correlate market impacts with production costs.

Applications

- Quantifying societal benefit
- Project justification
- Quantifying economic performance of transmission operations

Financial Transmission Rights (FTR)

Description

FTR acts as a hedge against congestion which provides a point-to-point financial hedge for congestion charge with a payment equal to the difference between the LMP between the point of injection and point of withdrawal.

Data Inputs

LMPs at locations under consideration.

Implementation Issue

For the implementation of FTR, the key issue is the strategy for initial allocation of the rights. FERC suggests two options to handle this – either assign the rights "directly" to those customers who paid embedded transmission costs, or conduct an auction and proportionately divide the rights, and further allocate proceeds of the auction to those customers who pay embedded costs.

Applications

- Quantifying societal benefit
- Project justification
- Project cost allocation/tariff design

Societal Benefits

Description

Societal Benefits reflect the total economic benefits of a transmission system, combining consumer economic and reliability surplus, producer surplus, and congestion revenues for transmission owners or transmission rights holders.

Data Inputs

Measurements used to quantify the societal benefits include:

- Reduced Operating Risks
  - *Mitigation of Fuel Cost and Generation Capability Risks* --- The reduced risks of fuel cost and generation capability afforded by transmission expansion.
  - *Improved Operating Flexibility* --- The possibility of greater flexibility that transmission expansion can provide in the scheduling of transmission maintenance and in reconfiguring the system during emergencies.
- Reliability Benefits
  - *Expected Unserved Energy* (EUE) --- EUE is a measure of transmission system capability to continuously serve all loads at all delivery points while satisfying all reliability criteria. Measured in MWh, EUE roughly equals the product of probability of outages occurring; MW magnitude of outages, and hours of duration of outages.
  - *System Performance* --- The effects of voltage limits on the transmission system's transfer capability and the likelihood of cascading power outage.
  - *Power System Externalities* --- The factors that have benefits or costs that are related to electricity production, including:
    - *Benefits Realized by Neighboring Systems*
    - *Improved Value of Other Planned Projects*
    - *Increased Transfer Capability Attributable to Higher Thermal Limits*
    - *Environmental costs such as* SO_2,NO_x,*and* CO_2.
- Environmental Benefits and Costs
  - *Societal Impacts* --- "Non-environmental" siting impacts, such as electromagnetic fields (EMF) and impacts caused by visual aesthetics.
  - *Environmental Externalities* --- Typically include river crossings, streams, wetlands, state natural areas, state parks, national forests and parks, tribal lands, and special waters areas; and on threatened, endangered, and special-concern species.
  - *Access to Renewable Resources*
- Benefits Related to Economic Development
  - *Local and State Economic Development* --- Direct impacts from investment in transmission facilities; and the indirect impacts due to changes (reductions) in electricity prices.
  - *Access to the High-Voltage Network* --- Benefits of reduced costs of interconnection to the high-voltage network.

- *LMP Comparability* --- The level of variation among the LMPs of different utility service territories. The average standard deviation of LMPs for each case can be used as a screening indicator of the fairness and equity.

Implementation Issue

The societal benefit is made up of a set of mutually agreed-upon metrics that reflect the economic performance of various aspects of transmission investment. These metrics can then be combined via a mutually agreed formula. The final metric reflects the overall societal benefit of a project. These metrics can be calculated for transmission alternatives and compared to assist in final project selection.

Applications

- Project justification
- Tariff design
- Cost allocation

Modified Societal Benefit

Description

The difference between total societal benefits and the monopoly rent.

Data Inputs

Modified Societal Benefits = Total Societal Benefits – Change of Monopoly Rent.

Implementation Issues

This metric is developed and used by the CAISO [33]. This metric assumes that the reduction in monopoly rent/profits from the exercising market power should be transferred to the consumers.

Applications

- Project justification
- Tariff design
- Cost allocation

Available Transfer Capability (ATC)

Description

ATC is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses. Transmission providers currently calculate the ATC for their systems using different assumptions and methodologies.

Data Inputs

ATC = TTC/TFC – (ETC+CBM+TRM)

where

TTC/TFC = Total Transfer/Flowgate Capability

ETC = Existing Transmission Commitments

CBM = Capacity Benefit Margin

TRM = Transmission Reserve Margin

Implementation Issues

FERC recognized that it is not the methodologies for calculating ATC themselves that create the opportunity for undue discrimination. Instead, the potential for undue discrimination stems from two main sources:

- Variability in the calculation of the components that are used to determine ATC
- The lack of a detailed description of the ATC calculation methodology and the underlying assumptions used by the transmission provider.

The combination of these two factors leaves customers and regulators unable to verify ATC calculations and may allow transmission providers to calculate ATC in different ways for different customers.

In order to minimize the discretion in the existing ATC calculation methodologies that gives transmission providers the ability and opportunities to unduly discriminate against third parties, FERC requires that all ATC components (i.e., TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent, and produce equivalent results [34].

NERC has proposed three standard methodologies for calculating ATC, which are:

- MOD-028 --- Area Interchange Methodology (or Network Response ATC Methodology), a standard that describes the calculation of TTC and ATC as performed primarily in the Eastern Interconnection.
- MOD-029 --- Rated System Path Methodology, a standard that describes the calculation of TTC and ATC as performed primarily in the Western Interconnection.

- MOD-30 --- Flowgate Methodology (Network Response Flowgate Methodology), a standard that describes the calculation of TFC and AFC, as well as the conversion of those values to TTC and ATC.

Applications

- Transmission service
- Project justification
- Regulatory measure of system benefit

Available Flowgate Capability (AFC)

Description

AFC is a measure of the flow capability remaining on a flowgate for further commercial activity over and above already committed uses.

Data Inputs

- When calculating firm AFC for a flowgate for a specified period, the transmission service provider (TSP) uses the following algorithm:

$$AFC_F = TFC - \left(ETC_{Fi} + CMB_i + TRM_i\right) + Postbacks_{Fi} + counterflows_{Fi}$$

where

TFC = Total Flowgate Capability

ETC_{Fi} = The sum of the impacts of firm ETC for the flowgate during that period

CBM_i = The impact of the CBM on the flowgate during that period

TRM_i = The impact of the TRM on the flowgate during that period

$Postback_{Fi}$ = Changes to firm AFC due to a change in the use of transmission service for that period

$counterflows_{Fi}$ = Adjustments to firm AFC as determined by the transmission service provider and specified in their "Available Transfer Capability Implementation Document (ATCID)"

- When calculating non-firm AFC for a flowgate for a specified period, the TSP uses the following algorithm:

$$AFC_{NF} = TFC - \left(ETC_{Fi} + ETC_{NFi} + CMB_{Si} + TRM_{Ui}\right) + Postbacks_{NFi} + counterflows_{NF}$$

where

TFC = Total Flowgate Capability

ETC_{Fi} = The sum of the impacts of firm ETC for the flowgate during that period

ETC_{NFi} = The sum of the impacts of non-firm ETC for the flowgate during that period

CBM_{Si} = The impact of any schedules during that period using CBM

TRM_{Ui} = The impact on the flowgate of the TRM that has not been released (unreleased) for sale as non-firm capacity by the TSP during that period

$Postback_{NF}$ = Changes to non-firm AFC due to a change in the use of transmission service for that period, as defined in Business Practices by NAESB

$counterflows_{NF}$ = Adjustments to non-firm AFC as determined by the TSP and specified in their ATCID

Implementation Issue

As indicated by NERC standard MOD-030-1, the TSP shall use the models provided by the transmission operator to determine AFC, and include in the model expected generation and transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the period calculated for the TSP's area, all adjacent TSPs, and any TSPs with which coordination agreements have been executed. For external flowgates, the AFC provided by the TSP can be used to calculate AFC for that flowgate.

Applications

- Transmission service
- Project justification
- Regulatory measure of system benefit

Existing Transmission Commitments (ETC)

Description

According to NERC reliability Standard MOD-001-1, ETC are the committed uses of the transmission system.

Data Inputs

The components of evaluating ETC include:

- Native load commitments including network service
- Grandfathered transmission rights
- Appropriate point-to-point reservations
- Rollover rights associated with long-term firm service
- Other uses identified through the NERC process.

Implementation Issue

FERC stated in [34] that ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which is to be addressed through CBM and TRM. In the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) shall be released as non-firm ATC.

Applications

- ATC/AFC calculations

Capacity Benefit Margin (CBM)

Description

CBM is a reliability margin that reflects the amount of firm transmission transfer capability preserved by the transmission provider for load serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet firm load obligations during a capacity emergency.

Data Inputs

The calculation of CBM varies across different transmission providers. NERC is in the process of developing standards for how the CBM value should be determined, allocated across transmission paths, and used.

Implementation Issue

FERC requires in [34] that transmission providers must reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service to ensure comparable treatment for point-to-point to customers. The transmission transfer capability preserved as CBM is intended to be used by the LSE only during capacity emergencies and is based on verifiable historical, state, TRO, or regional generation reliability criteria requirements such as reserve margin, loss of load probability, the loss of largest units, etc.

Applications

- ATC/AFC calculations
- Transmission service

Transmission Reliability Margin (TRM):

Description

TRM is the amount of necessary transmission transfer capability preserved by the respective transmission system providers to provide reasonable assurance that the interconnected transmission network will be secure given uncertainty in system conditions and the need for operating flexibility.

Data Inputs

The components of uncertainty that may be used in establishing TRM include:

- Aggregate load forecast
- Load distribution uncertainty
- Forecast uncertainty in transmission system topology including maintenance outage
- Allowances for parallel path (loop flow) impacts
- Allowance for simultaneous path interactions
- Variations in generation dispatch
- Short-term system operator response
- Reserve sharing requirements
- Inertial response and frequency bias

Implementation Issues

Marketers use ATC and TTC data to propose transactions and make reservations for transmission services. Numerical errors exist in the offline ATC or TTC as it neglects reactive power and uses linear models with constant distribution factor. The TRM is used nowadays to account for these errors. TRM provides a safe margin for transmission elements for unanticipated events, failures, and changes in system. But TRM can reduce the effective utilization of a transmission system. Hence, according to NERC regulation, a portion of the TRM can be sold to the market for non-firm transactions if the utility can prove that the system is not in a vulnerable state.

Applications

- ATC/AFC calculations
- Transmission service

Transmission Loading Relief (TLR)

Description

TLR is a procedure for curtailment and reloading of interchange transactions to relieve overloads on transmission facilities. The transmission loading relief is defined as an incremental power injection at a given bus *k* (P_k) impacts power flow (P_{ij}) on a transmission branch. Empirically it can be defined as

$$TLR_{BUSk,Branchij} = \frac{\Delta P_{ij}}{\Delta P_k}$$

Available Transfer Capability (ATC) and Total Transfer Capacity (TTC). ATC and TTC were created to provide open access transactions on the transmission network such that maximum transactions at any time over a transmission element can be determined. The transfer capacity calculations are done using linear methods. A large portion of these calculations utilize load flow technique to predict changes in line loading due to transfers and line outages.

Data Inputs

Power flow data for the base case and contingencies, PTDF, LODF, ATC, and TTC calculations are required to calculate TLR. Power Transfer Distribution Factor (PTDF) and Line Outage Distribution Factor (LODF) are two basic calculations to provide inputs for the transfer capacity calculation. TLR, Available Transfer Capability (ATC), and Total Transfer Capacity (TTC) depend on each other [11].

Implementation Issues

TLR procedure is only needed if the ATC of certain transmission elements or TTC of a transmission system is violated. Hence, if the ATC and TTC calculations are accurate, TLR procedure is only needed for unanticipated system changes. Such system changes can be due to system loading pattern, status of line and facilities, generation scheduling, and model parameter values.

Applications

- System performance
- Project justification
- Operational effectiveness

ISO Ratepayers Benefit

Description

The benefits entitled to entities that fund the project within the control area — consumers, transmission owners, and utility generators.

Data Inputs

ISO Ratepayer Benefit = Change of consumer surplus + Change of producer surplus for utility retained generation + Transmission rental for the ISO control area.

Implementation Issues

This metric is developed and used by the CAISO [33].

Applications

- CAISO project justification

ISO Participant Benefit

Description

The benefits entitled to the ratepayers and independent power producer (IPP) derived from competitive market conditions.

Data Inputs

ISO Participant Benefit = Change of consumer surplus + IPP competitive rent excluding monopoly rent + Transmission rental for the ISO control area.

Implementation Issues:

This metric is developed and used by the CAISO to promote merchant generation investment [33].

Applications

- CAISO project justification

All-Hours Shadow Price

Description

This metric identifies the paths that had the greatest marginal cost impact on generation costs by calculating the shadow price averaged over all hours in the modeled year for each path.

Data Input

The marginal cost of generation re-dispatch required to adhere to the transmission constraint over all hours in a year.

Implementation Issue

The shadow price for a given path is zero unless the path is loaded to its limit. This metric is created and used by the Department of Energy (DOE) in their report entitled National Electric Transmission Congestion Study [21].

Applications

- Estimating LMP
- Project justification
- DOE metric

Binding Hours Shadow Price

Description

The average shadow price over only those hours during which the constraint is binding.

Data Input

Shadow price and the hours when a single constraint is binding.

Implementation Issue

Transmission congestion varies across time, and the cost imposed by a single constraint can vary widely as well. This metric indicates the cost imposed by a single constraint. Shadow price is zero when the constraint is not binding. This metric is created and used by DOE in their report entitled National Electric Transmission Congestion Study [21].

Applications

- Estimating LMP
- Project justification
- DOE metric

Congestion Rent

Description

Congestion rent is calculated by summing the shadow price times flow over all the hours when the constraint is binding. This metric is estimated for each constraint and is used to indicate and rank the severity of transmission congestion at the various locations on the transmission system.

Data Input

Shadow price, flows, and the hours.

Implementation Issue

This estimate should not be assumed to equal the benefits that might be achieved by expanding the transmission system to eliminate that constraint, and should not be compared to the cost of any such expansion. This metric is created and used by DOE in their report entitled National Electric Transmission Congestion Study [21].

Applications

- Estimating LMP
- Project justification
- DOE metric

Change in Production Cost

Description

This is the primary congestion impact metric chosen for use by the NYISO Operating Committee and measures the economic inefficiency introduced by the existence of transmission bottlenecks. It is calculated by comparing the total production cost based on mitigated bids with or without transmission constraints limiting the unit commitment and dispatch. This is the *societal cost* of transmission congestion [15].

Data Input

Total production costs with and without transmission constraints.

Implementation Issue

The direct objective of Security Constrained Unit Commitment software (SCUC) used by NYISO is to minimize bid production cost, and LMPs are the results of the unit commitment and dispatch that serve to achieve this objective. Therefore, relieving some or all of the constraints may or may not decrease the market-based electricity cost to load. A positive number means that transmission congestion increased electricity production cost.

Applications

- Project justification in NYISO

Change in Congestion Payments

Description

The sum of the LMP congestion component times the load affected.

Data Input

LMP congestion component and the load affected.

Implementation Issue

This is the *accounting cost* of congestion used by NYISO [15]. Congestion payments can be hedged with transmission congestion contracts (TCCs) resulting in the unhedged congestion numbers reported. NYISO assumes that all TCCs are owned by load and are available for hedging congestion payments. A positive number means congestion increases load cost.

Applications

- Project justification in NYISO

Change in Generation Payments

Description

In addition to the LMP payments to generation, generators are also paid a Bid Production Cost Guarantee (BPCG) and for Ancillary Services (AS). This metric is created and used by NYISO [15].

Data Input

Payment received by generators for BPCG and AS.

Implementation Issue

BPCG compensates generators that are committed to reliability despite the fact that their bids are greater than the LMP at the generator location. This differential in cost can happen if ramp rates, minimum run times, or other limits force unit operation. The effect is to minimize overall production cost, including BPCG payments. A positive number means generation payments went up due to congestion.

Applications

- Project justification in NYISO

Change in Load Payments

Description

This metric is the opposite side of the generation payments calculation and determines how much more load actually pays due to congestion and the market design; that is, the *bill's impact*. It reflects the local energy cost response when transmission constraints are removed [15].

Data Input

LMP components, load payments, TCC shortfall or surplus, and energy and loss payment imbalance.

Implementation Issue

This metric includes the effect of all market segments that can change when transmission constraints are relieved. A positive number means congestion increases load payments.

Applications

- Project justification in NYISO

Adjusted Production Cost (APC)

Description

APC captures the underlying production cost savings due to reduction in congestion on the system resulting from the various transmission alternatives under consideration. This metric is developed and included in the PROMOD LMP evaluation model used by American Transmission Company [22].

Data Input

Adj Prod Cost = Production Cost –Profits from Sales + Savings from Purchases.

Implementation Issue

APC is especially useful for comparing transmission alternatives among each other to determine relative economic performance. This metric can also be used directly in the calculation of present value and net revenue requirement for the purpose of regulatory justification.

Applications

- Project justification in American Transmission Company

2.2.3 Performance Metrics

In its report [34], FERC requires transmission providers to post the performance metrics so that it may track their performance in processing system impact studies and facilities studies associated with request for transmission service.

List of Performance Metrics

- Standard Performance Metrics
- Additional Performance Metrics

Standard Performance Metrics

Description

FERC requires transmission providers to post the performance metrics proposed in the NOPR and revised by the Final Rule [34] on their Open Access Same-time Information System (OASIS) sites. The metrics will enhance the transparency of the study process and shed light on whether transmission providers are processing request studies in a non-discriminatory manner.

Data Inputs

A transmission provider is required to post the following set of performance metrics on a quarterly basis:

- Process time from initial service request to offer of system impact study agreement pursuant to sections 17.5, 19.1, and 32.1 of the pro forma OATT
    - Number of new system impact study agreements delivered to transmission customers
    - Number of new system impact study agreements delivered to the transmission customer more than 30 days after the transmission customer submitted its request
    - Average time (days) from request submittal to change in request status
    - Average time (days) from request submittal to delivery of system impact study agreement
    - Number of new system impact study agreements executed

- System impact study processing time pursuant to sections 19.3 and 32.3 of the pro forma OATT
    - Number of system impact studies completed
    - Number of system impact studies completed more than 60 days after receipt of executed system impact study agreement
    - Average time (days) from receipt of executed system impact study agreement to date when completed system impact study made available to the transmission customer
    - Average cost of system impact studies completed during the period

- Service requests withdrawn from system impact study queue
    - Number of requests withdrawn from the system impact study queue
    - Number of system impact studies withdrawn more than 60 days after receipt of executed system impact study agreement
    - Average time (days) from receipt of executed system impact study agreement to date when request was withdrawn from the system impact study queue
    - For all system impact studies completed more than 60 days after receipt of executed system impact study agreement, average number of days study was delayed due to transmission customer's actions (e.g., delays in providing needed data)

- Process time from completed system impact study to offer of facilities study pursuant to sections 19.4 and 32.4 of the pro forma OATT

    - Number of new facilities study agreements delivered to transmission customers
    - Number of new facilities study agreements delivered to transmission customers more than 30 days after the completion of the system impact study
    - Average time (days) from completion of system impact study to delivery of facilities study agreement
    - Number of new facilities study agreements executed

- Facilities study processing time pursuant to sections 19.4 and 32.4
    - Number of facilities studies completed
    - Number of facilities studies completed more than 60 days after receipt of executed facilities study agreement
    - Average time (days) from receipt of executed facilities study agreement to date when completed facilities study made available to the transmission customer
    - Average cost of facilities studies completed during the period
    - Average cost of recommended upgrades for facilities studies completed during the period

- Service requests withdrawn from facilities study queue
    - Number of requests withdrawn from the facilities study queue
    - Number of facilities studies withdrawn more than 60 days after receipt of executed facilities study agreement
    - Average time (days) from receipt of executed facilities study agreement to date when request was withdrawn from the facilities study queue

- For all facilities studies completed more than 60 days after receipt of executed facilities study agreement, average number of days study was delayed due to transmission customer's actions (e.g., delays in providing needed data)

Implementation Issues

The transmission providers are required to post their quarterly performance metrics within 15 days of the end of the quarter and keep the metrics posted on their OASIS sites for three calendar years. The performance metrics outlined above must be calculated separately for affiliates and non-affiliates and requests for short-term and long-term transmission service [34].

Applications

- Regulatory metric for generation interconnection request processing
- Operational efficiency

Additional Performance Metrics (after two quarters of late studies)

Description

FERC requires transmission providers to provide a notification filing and the posting of additional metrics if a transmission provider completes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadline in the pro forma OATT for two consecutive quarters.

Data Inputs

- A notification filing in the event the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the pro forma OATT for two consecutive quarters.
- Starting the quarter following a notification filing, the transmission provider will be required to post:
  - The average, across completed system impact studies, of the employee-hours expended per completed system impact study.
  - The average, across completed facilities studies, of employee-hours expended per completed facilities study.
  - The number of employees devoted to processing system impact studies.
  - The number of employees devoted to processing facilities studies.

Implementation Issues

The notification filing must be filed within 30 days of the end of the second quarter during which the transmission provider processes more than 20 percent of non-affiliates' studies outside of the 60-day due diligence deadlines in the pro forma OATT. For the purposes of calculating this notification trigger, the transmission provider is required to aggregate all system impact studies and facilities studies that it completes during the quarter for non-affiliates. The transmission provider may explain in its notification filing that it believes there are extenuating circumstances that prevented it from meeting the deadlines in the pro forma OATT.

The transmission provider is not required to post these additional performance metrics separately for affiliates' and non-affiliates' requests for transmission service and for short-term and long-term transmission service. The transmission provider is instead required to aggregate studies associated with requests for short-term and long-term transmission service when calculating these additional metrics.

The transmission provider is not required to post the additional metrics if the Commission concludes that delays in study completion are due to extenuating circumstances. However, the transmission provider is required to post the additional metrics while the Commission considers the transmission provider's notification filing arguing that extenuating circumstances prevented it from processing request studies on a timely basis. Based on the timing described in this Final Rule, the transmission provider will be required to post the additional performance metrics approximately two months after the provider makes its notification filing. The Commission will have this time to evaluate the transmission provider's contention that it was unable to complete request studies due to extenuating circumstances. As a result, FERC expects the transmission provider with legitimate extenuating circumstances typically will not have to post any additional metrics [34].

Applications

- Regulatory metric for generation interconnection request processing
- Operational efficiency

2.3 Blended Metrics

Currently, the industry typically uses deterministic processes to identify small sets of alternative projects and then uses extensive security-constrained economic dispatch models to finalize selection. This process is extremely time consuming and does not allow for detailed analysis. As the planning boundary expands regionally, and potentially multi-regionally, the set of possible projects becomes enormous and this sequential approach may not be sufficient for satisfying regulators that the “right’ project is being proposed.

Recently, attempts have been made to find ways to efficiently screen large sets of alternative projects for regional planning entities. This section describes one promising approach that takes advantage of the fact that economic benefits are highly correlated with congestion relief and the fact that congestion can be identified in steady-state models.

Weighted Flowgate Loading Relief

Description

In [11], the authors proposed a performance metric to quantify the Transmission Loading Relief (TLR) for proposed new transmission lines by calculating Aggregate MVA Contingency Overload (AMVACO). An integration of the concept of AMVACO and TLR can provide the impact of an incremental power injection on all contingent overloaded branches. The authors refer to this metric as Weighted Flowgate Loading Relief (WFLR).

Data Inputs

Aggregate MVA Contingency Overload (AMVACO) is defined as:

$$AMVACO = \sum_{c=CONT} \sum_{ij=Branch} \left(MVA_{ij,c} - Rating_{ij} \right) \big|_{MVA_{ij,c} > Rating_{ij}}$$

And the Weighted Transmission Loading Relief (WFLR) is defined as:

$$WFLR_k = \frac{N_{cont}}{SysAMVACO} \sum CODir_{branchij} TLR_{BUSk,Branchij} AMVACO_{Branchij}$$

Implementation Issues

This TLR-based methodology enables an easily automated process for selecting a sequence of new transmission lines. Thus, it serves as a fast-screening tool to allow a system planner to evaluate a large number of alternatives beyond those considered in a purely manual process. This fact, in and of itself, demonstrates the importance of the approach. In today’s world of limited (and shrinking) transmission planning expertise, the ability to screen a large number of alternatives to determine a subset of promising alternatives for further evaluation (e.g., economic analysis using security-constrained economic dispatch algorithms) is an important advancement.

However, it should be noted that this process is not to be used as the sole consideration in designing transmission system additions. Several important considerations cannot be adequately addressed by an automated TLR-based selection process.

A transmission plan should facilitate multiple transfers of power over the future grid, in addition to system security. These objectives typically require multiple projects to be performed simultaneously. However, this automated process can only evaluate one dispatch and load pattern at a time. Furthermore, the method only has visibility to the next connection in the sequence. It can estimate which single connection will have the greatest marginal benefit to system security, but it cannot assess multiple connections simultaneously. After each new transmission line selection, the AMVACO and WFLR must be recalculated to assess actual system security changes and incorporate any newly created overloads. Some proposed connections may worsen system security, even following several subsequently proposed connections. Also, the WFLR calculations are sensitive to the set of monitored transmission element and contingencies. Assumptions have a significant impact on results.

Minimizing the cost and maximizing the performance of the entire system often requires consolidating connections in a given locality around as few substations as possible. Because the automated process can only evaluate the cost of the next connection, it may not recognize such opportunities for consolidation. The process may also propose connections with external liabilities, such as those that cross environmentally sensitive areas.

Finally, it may not be feasible or cost effective to relieve all forms of congestion with new transmission lines. For example, if a transformer is slightly overloaded, it may be more cost effective to add another transformer in parallel, rather than redirect flow away from its substation with an EHV line. Similarly, some individual lines that become slightly overloaded may be effectively upgraded with reconductoring. Still other security problems may be averted with special protection schemes, especially those that occur rarely or only under specific circumstances. EHV expansion as an enabler of system security is most effective where several regional issues may be remediated with a few new EHV connections.

Several other analysis tools may be applied concurrently with the TLR-based selection process to overcome some limitations and design a system that better facilitates economic transfers. A production cost-based unit commitment and dispatch, performed prior to the transmission line selection process and with minimal or no enforcement of existing transmission and security constraints, forces the TLR-based process to alleviate overloading resulting from such purely economic considerations. In addition, the selection process may be repeated with multiple hourly and seasonal system conditions and multiple portfolios of future generation capacity, leading to multiple corresponding transmission line selection sets. A security-constrained unit commitment and economic dispatch may then be performed on the alternative transmission grids determined by the TLR-based process and other planning criteria. The best alternative would yield the lowest cost of system operation with such security constraints.

3
CASE STUDIES

3.1 California Independent System Operator (CAISO)

California Independent System Operator (CAISO) strives to be a world-class electric transmission organization built around a globally-recognized and inspired team providing cost-effective and reliable service, well-balanced and transparent energy market mechanisms, and high-quality information for the benefit of customers. The CAISO operates two control centers on a 24/7 basis with at least 12 grid operators on shift around the clock. Folsom, California is home for the organization's main control center. A second center in southern California is a fully-functioning facility, ready within minutes to assume control of the ISO. As one of three Reliability Coordinators for the Western Electricity Coordinating Council (WECC), the CAISO also monitors transmission activity for a portion of 14 western states, Alberta, British Columbia, and northern Mexico.

CAISO has developed a planning approach called the Transmission Economic Assessment Methodology (TEAM) for evaluating the need for all potential transmission upgrades that California ratepayers may be asked to fund [29]. This includes construction of transmission projects needed either to promote economic efficiency or to maintain system reliability. The CAISO has clear standards to use in evaluating reliability-based projects. TEAM helps the CAISO to fulfill its responsibility for identifying economic projects that promote efficient utilization of the grid.

The goal of TEAM is to streamline the evaluation process for economic projects, improve the accuracy of the evaluation, and add greater predictability to the evaluations of transmission need conducted at the various agencies. The TEAM methodology is based upon five principles for defining quantifiable benefits for assessing the economic benefits of transmission expansions for wholesale market environments in the face of uncertainty. These five key principles are:

- **Benefit Framework –** Standardized benefit cost framework for measuring transmission expansion benefits regionally and separately for consumers, producers, and transmission owners for any kind of economic-driven transmission investment.
- **Network Representation –** Modeling of physically feasible flows, a full network model with linearized DC approximation and nodal pricing.
- **Market Prices –** Utilize dynamic generation bidding to capture beyond the cost aspects and the non-competitive market conditions.
- **Uncertainty –** Measurable and non-measurable variations in system conditions, analysis using deterministic or stochastic system conditions or a combination of both, compute expected value, most likely range, and insurance value of a proposed upgrade.
- **Resource Substitution –** Evaluate other alternative transmission and generation projects.

TEAM has been applied to evaluate a possible upgrade of Path 26, a major 500-kV path between central and southern California, in which the above listed five key principles are examined in detail as follows.

Benefit Framework

The CAISO divided the total change in production costs resulting from the transmission expansion into three components — consumer surplus, producer surplus, and transmission owner (congestion revenue) benefits — and summarized four perspectives when evaluating the economic viability of the proposed upgrade: WECC societal benefits, WECC modified societal benefits, CAISO ratepayer benefit, and CAISO participant benefit. The CAISO calculated the benefit for each of them for two different scenarios developed for 2013; one assumes no market power (cost-based bidding) and the other assumes baseline bid markups (market-based bidding). The results provide the possible distribution of benefits in 2013 for WECC and CAISO, assuming baseline values for load growth, gas prices, and hydrological conditions. The results show that the market-power-mitigating effects of transmission are the major source of projected consumer benefits for Path 26. The proposed upgrade reduced congestion and associated congestion revenue, and the transmission owner saw a significant decline in revenue.

Network Representation

Power production costs and market prices were calculated for the entire WECC using the linear programming-based market simulation package PLEXOS software from Drayton Analytics. A linearized DC load flow was included in the model that represented transmission constraints at the 500-kV level, but also flows at lower voltages. LMPs were reported as dual variables from the linear programming solution. For the cost-based scenario, the production costs are set to be the objective function, while for the market-based pricing scenario, assumed bid functions were substituted for production costs in the objective function.

Impact of Uncertain Variables

In general, the relationship between transmission benefits and underlying system conditions is nonlinear. A complete transmission evaluation should incorporate stochastic analysis to model the uncertainty associated with different parameters affecting the magnitudes of benefits to be derived from an expansion project. Stochastic analysis often uses probabilistic representations of the future loads, gas prices, and generation unit availabilities. The CAISO performed sensitivity studies to compute the risk measures like expected value, range, and values under specified rare but potentially important contingencies such as loss of a major transmission line.

The analysis for Path 26 shows the potential impact of the uncertainty in individual variables on the annual CAISO Participant benefits in 2013 [30].

Probable Benefit and Cost Range

The CAISO estimated a “most-likely” benefit and a “possible” cost range based on the 22 cases for 2013 that have a probability assigned to them. A linear programming approach [30] is used to choose a set of probabilities that result in the maximum expected benefit subject to the constraints on the marginal distributions of demand, gas price, hydropower, and market power. The joint distribution is chosen in such a way that the means and variances of the marginal distributions match the error distributions of historical CEC forecasts, actual production, or a regression model of price markups. The difference in benefits with and without upgrade was then calculated based on the probability-weighted results from the network simulations and compared to evaluate the proposal of upgrading.

Resource Alternatives to Transmission Expansion

The economic value of a proposed transmission upgrade directly depends on the cost of resources that could be added or implemented in lieu of the upgrade. The best means to account for the plans of a host of private investment decisions is to model the profitability of the generation decision in the transmission framework. The CAISO uses a "what if" framework for their standard decision analysis.

For the Path 26 case, the CAISO assumed that the DC Intertie was unavailable for the entire year. Then it calculated and compared the CAISO Participant benefits in 2013 with and without the upgrade. The results show that although the *value* of the Path 26 upgrade is substantial in this case, the *expected value* of the upgrade in this situation is negligible since the probability of the event is so low. However, in order to avoid the full consequences of a year-long DC outage, the additional fee that ratepayers might be willing to pay as an insurance premium could be significantly larger than the expected value, and may be an important part of the overall benefits.

3.2 Southwest Power Pool

The Southwest Power Pool (SPP) is located in the south-central United States. This area is a key location for projected wind development. The SPP transmission system also currently shows a need for reinforcement between the eastern and western portions of the system. As a result, SPP sought to develop a long-range EHV overlay to reliably serve its customers under anticipated system conditions in 2026. For the analysis [35], several generation portfolio scenarios were considered, including a baseline, high renewable energy growth, high nuclear growth, no nuclear growth, and high natural gas growth. Because of the size and complexity of the SPP system, the project team used the WFLR approach to screen alternatives and evaluate performance.

The WFLR process used candidate EHV lines between all bus pairs that connected 230 kV and higher buses within SPP and 345 kV and higher buses with SPP's immediate neighbors. There were 356 buses in the evaluation set. Candidates were initially screened by distance, assuming that EHV lines longer than 500 miles would be impractical for power transmission and lines shorter than 30 miles would not provide enough marginal benefit to justify the investment in EHV terminations. Each remaining pair was considered for 765-kV single-circuit, 500-kV double-circuit, or 500-kV single-circuit connections, yielding approximately 82,000 candidate EHV lines.

For contingency analysis, the set of monitored lines included all non-radial lines and transformers in SPP with a maximum nominal voltage of at least 230-kV. The set of contingencies included the following:

1. Loss of single line or transformer (N-1) in SPP with minimum nominal voltage of at least 345 kV.
2. Loss of single largest generator at all plants in SPP with capacity of at least 100 MW.
3. All outages represented in the list of SPP-supplied flowgates, not included in 1 or 2.

Simulations and linear sensitivity calculations were performed on PowerWorld Simulator software. AMVACO measures were calculated for the base-case system to identify key points of congestion. Figure 3-1 below shows a color contour of the AMVACO observed by the team for each transmission branch prior to designing the EHV overlay.

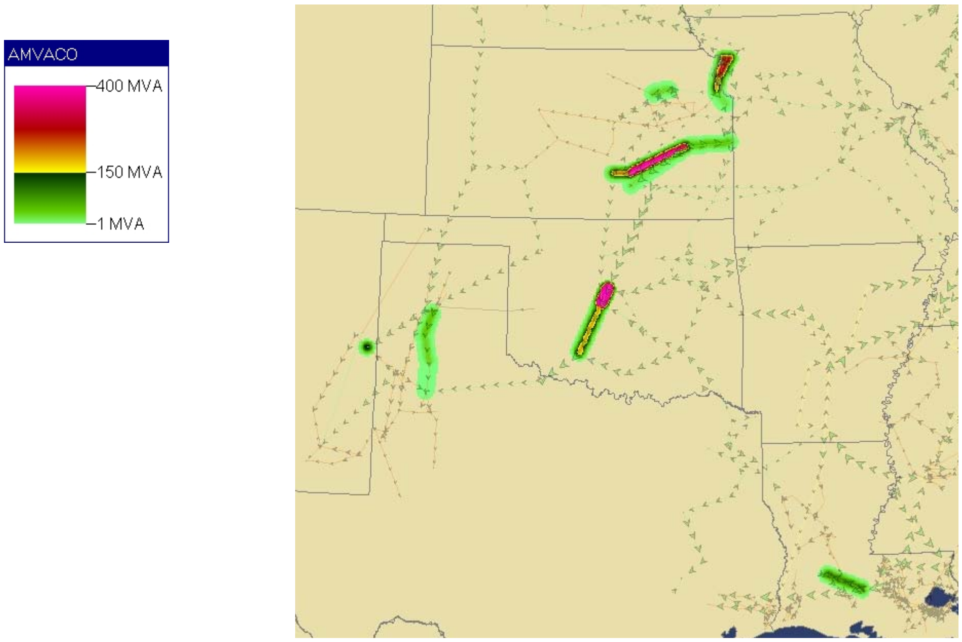

Figure 3-1
Initial AMVCO, 2026 SPP Transmission System

The WFLR process uses a linearization of the system and then injects and removes 1 MW of power for each candidate line. Because the analysis was performed entirely in steady state at peak, the team was able to automate the process and set up batch runs, creating lists of high-performing (i.e., reduced AMVACO) projects for further, detailed analysis. The automation process used by the team added the highest performing line to the model using standard line parameters for 765-kV and 500-kV lines. The automation continued to loop until no further improvement could be made in reducing AMVACO.

The team observed that some selections actually worsened the AMVACO security measure by causing new base-case or contingent overloads. It was pointed out that an increase in AMVACO by itself does not indicate that a proposed line should not be considered. In this example, new overloads were relieved by subsequent connections, which extend the proposed line to the next substation. Where the AMVACO was worsened by a line selection and not restored to a lower level within a few subsequent selections, it may be concluded that the line has an adverse impact on system security.

Figure 3-2 shows graphically the transmission lines selected by the automated WFLR process.

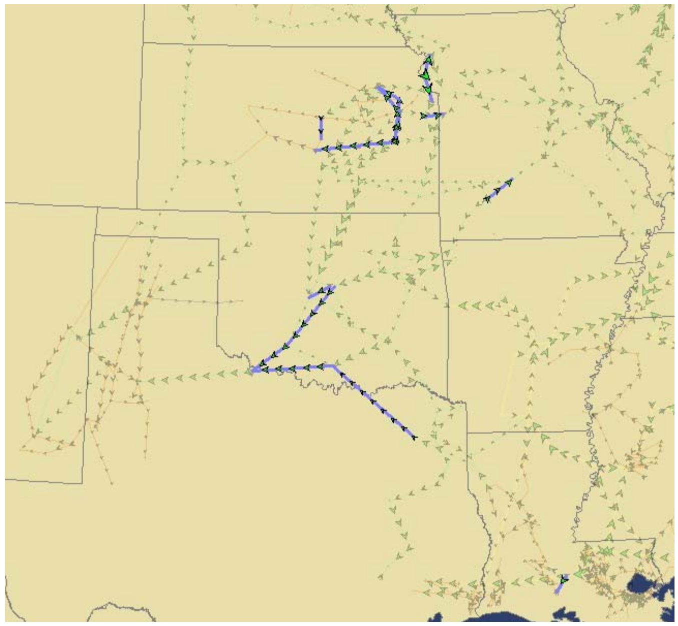

Figure 3-2
WFLR-based Transmission Plan

The team did not ultimately recommend this set of lines. However the process proved useful in evaluation and comparing with the final EHV grid recommendations. The team noted that other considerations factored into the final recommendation, including alternate future generation portfolio scenarios such as expansion of the renewable energy portfolio. The final recommendations also linked the EHV substations into a contiguous overlay to enhance flexibility in regional power transfers

In a subsequent paper jointly authored by SPP and the members of the project team [12], the authors noted that the process proved useful in visualizing congestion, evaluating large sets of alternatives, and benchmarking performance of the final alternative set of projects selected for detailed analysis.

3.3 Commonwealth Edison

Commonwealth Edison (ComEd) is the electric utility that serves most of Northern Illinois, including the city of Chicago. It has more than 3.5 million customers and a peak demand greater than 21 gigawatts. In the summer of 1999, three major outages occurred in ComEd's territory. These outages were primarily related to outages within substations that serve Chicago.

ComEd immediately launched a comprehensive investigation to review the summer outages and develop a plan to achieve fundamental improvements. This effort was described by EPRI as "the fastest, fullest, most comprehensive T&D investigation ever launched in the history of the industry, taking a blunt look at equipment, design, personnel and operations." The investigation resulted in a large list of tasks intended to improve system reliability before the summer of 2000.

These projects included substation and feeder inspections, new feeders, feeder upgrades, substation expansions, a new substation, and aggressive equipment maintenance.

Prior to 1999, the primary metric used to drive spending decisions was kilovolt-amperes of equipment capacity. This led to a Chicago system that had many characteristics that were undesirable from a reliability perspective, including many substation transformers with a dedicated transmission line. If a transmission line was interrupted, the associated transformer could not be switched to other transmission lines serving the substations. It also included a radial transmission sub-transmission topology in Chicago. If a radial path experienced an outage, downstream substations could not be served from alternate directions. Last, it included very old equipment in many substations. Investments to address any of these issues would not result in increased kVA of capacity, and therefore was assigned very little value.

Clearly ComEd was in need of new planning criteria. It engaged a consultant and, in cooperation with the Illinois Commerce Commission (ICC) and the City of Chicago, developed a probabilistic measure of reliability called Expected Energy at Risk (EEAR). The initial EEAR was computed for Chicago, and five-year EEAR improvement targets were set based on a benchmark study of comparison cities.

EEAR is equal to the amount of energy over the course of a year that would have to be shed so that no piece of transmission or substation equipment would have to be loaded above its normal rating. This includes effects such as hourly loading, transmission line failures, substation equipment failures, substation reconfiguration, and load transfers from one substation to another. The effect of load growth can also be computed by performing an EEAR analysis with higher loading levels.

EEAR is computed for each substation. First, the normal configuration of the substation is considered. The amount of load that the substation can serve without exceeding any normal equipment ratings is determined. This is called the normal capacity of the substation. Then, a full year of hourly loads (based on historical data) is compared to this normal capacity. If the hourly load exceeds the normal substation rating, the excess is recorded as energy at risk. This amount may be reduced if load transfers to adjacent substations are possible. Next, the process is repeated for all N-1 conditions, N-2 conditions, and higher order contingencies up to N-8. The total of all accrued energy at risk is defined as EEAR. EEAR is then divided by the total demanded energy over the year to give a percentage. For example, an EEAR of 0.5% means that 0.5% of all energy demanded will result in equipment exceeding normal ratings.

Each year, EEAR was computed for each substation, and then the average EEAR was used to track the overall reliability of Chicago. EEAR was able to balance kVA investments with substation switching capability, a more robust sub-transmission topology, aggressive substation maintenance, and increased load transfer ability between substations. Between 2000 and 2005, ComEd spent over $1 billion improving the reliability of Chicago based on EEAR analysis, with close coordination with the ICC and the City of Chicago. After five years, the Chicago sub-transmission and substation system was completely overhauled and EEAR was reduced by a factor of five.

Exelon, the parent company of ComEd, also performed an EEAR analysis for Philadelphia. The EEAR of several substations resulted in reliability improvement projects, but the overall EEAR of Philadelphia was acceptable and no comprehensive reliability improvement program for Philadelphia was deemed necessary.

3.4 Eskom (South Africa)

Eskom is the largest producer of electricity in Africa, and is among the top seven utilities in the world in terms of generation capacity. One of Eskom's planning considerations is societal cost optimization, where the sum of utility and costs and the customer costs (including the cost of poor reliability) is minimized. This is done largely through the adoption of deterministic planning criteria, such as N-1, where the system can withstand an outage of any single major piece of equipment. Balancing the concept of deterministic criteria and societal cost minimization is difficult, and Eskom has struggled with questions such as the following:

- Who should pay for incrementally high levels of reliability?
- Is it valid to use customer cost surveys in the transmission planning process?
- What is the appropriate use of predictive reliability models?
- How should "free riders" be considered, when certain customers benefit from reliability improvements paid for by others?
- What probabilistic criteria are appropriate for transmission planning, and how does this impact traditional planning criteria?
- How should interest rates, inflation, discount rates, net present value calculations, and profitability ratios be interpreted and practically applied in the transmission planning process?

Planning criteria for Eskom are documented in its Transmission System Planning Guidelines (TSPG). The stated purpose of the TSPG is to provide a framework for the transmission expansion planning process to achieve the following stated mission:

<u>Mission of Transmission Expansion Planning</u>

To continuously satisfy the expectations of our customers and stakeholders by optimizing development of bulk electricity transmission networks, efficiently linking producers and consumers of electricity in South Africa in an innovative way subject to technical, economic, environmental and acceptable quality of supply constraints.

By definition, therefore, transmission expansion planning at Eskom must consider reliability criteria. The six major activities of transmission expansion planning as stated in the TSPG are the following:

<u>Six Major Activities of Transmission Expansion Planning</u>

1. Determine the need for expansion or strengthening.
2. Formulate alternative plans to meet this need.
3. Study these plans to ensure compliance with agreed technical limits and criteria, and justifiable reliability and quality of supply standards.
4. Cost plans on the basis of present-day standard capital costs, and using appropriate net discount rates, establish the annual cost of each plan and the most cost-effective alternative that meets the technical requirements.

5. Investigate the economic justification of the most cost-effective plan by comparing the cost to the economy of the probable energy not supplied due to contingencies with the cost of reducing the unsupplied energy.
6. Obtain approval of recommended plans and initiate execution.

3.4.1 Contingency Criteria

The TSPG requires contingency studies to be performed for each planning area for the next 10 years based on a demand forecast (it is beyond the scope of this study to assess the process underlying the demand forecast). These contingency studies should ensure that “plans for expanding or strengthening the interconnected transmission system should be formulated on the basis of at least the N-1 criterion and on the basis of the N-2 criterion where appropriate.”

The N-1 criterion is justified as follows: “To make it possible to give customers firm supplies, the interconnected transmission system must be designed to meet the specified limits and criteria for, at least, any N-1 contingency. For an interconnected system with many lines the cost of providing a system capable of meeting the N-1 criterion is usually relatively small and can be justified economically and included in the tariff applicable to all supplies.” This reasoning is typical for utilities in economically developed countries.

The N-2 criterion is treated as follows: “For lines and other system components used to connect large base-load power stations to the system, or for other situations where the load not supplied due to an outage can be very large, there may be an economic case for allowing for a double outage, the N-2 criterion, and including the cost of this in the general tariff.” This is not a criterion *per se*, but a statement that does not preclude an N-2 approach if a compelling economic case can be made.

Substations are treated a bit differently, with prescriptive recommendations for transformer selection and bus configuration. The TSPG implies that the default for new power substations is a “six-pack” configuration, which resembles a main-and-transfer bus scheme with additional breakers segmenting the main bus into generator/load pairs (see Figure 3-3).

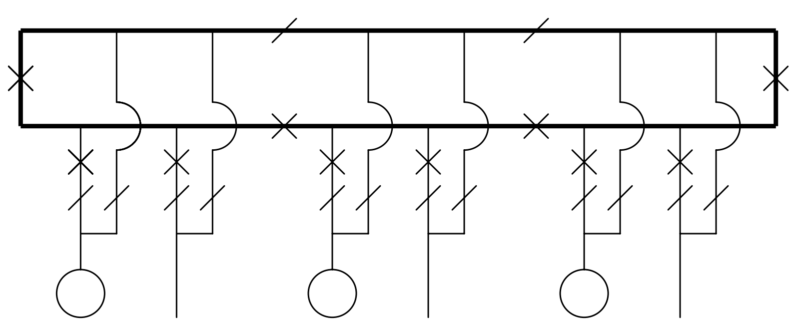

Figure 3-3
“Six-Pack” Substation Configuration

The TSPG also offers general criteria for selecting a substation bus configuration strategy including:

- Double busbar selection with bypass to be provided on all 765-kV and 400-kV feeders. At 275-kV or 220-kV, no circuit breaker bypass facilities are normally provided with firm supplies.
- Double busbar selection with bypass to be provided on all single unfirm radial feeds at voltages above 132-kV.
- For feeder breakers of 132-kV and below, the provision of bypass facilities to be considered on individual merit normally depending on the importance of the customer and whether this is economically justifiable.
- For GIS stations, bypass facilities to be considered on individual merit.
- Should the customer require additional facilities to those provided in terms of these criteria, these may be provided but at the customer's expense.

The TSPG also recommends that the N-1 criteria be held for substation transformer capacity. Specifically, the guide recommends that initial transformer selection be made based on a five-year forecast, and that peak transformer loading with one unit out of service should not exceed 120% of nameplate. The guide also recognizes more sophisticated emergency loading criteria and encourages their use to replace the 120% rule of thumb. The guide also encourages the use of two transformers (rather than three or more) due to savings in related switchgear.

The criteria in the TSPG do not consider the ability to transfer load to other substations. For example, if a substation serves a peak load of 60 MVA and the 120% transformer emergency loading rule applies, each transformer must be sized at 50 MVA. However, if 20 MVA of load is able to be transferred to other substations, each transformer need only be sized at 33 MVA while allowing the 120% rule to still be valid.

3.4.2 Reliability Criteria

The single probabilistic reliability criteria described in the TSPG is Expected Energy Not Served (EENS). Equations describing this metric are:

EENS	=	EEAR * P(f)
EEAR	=	All the energy above the rating of the firm network (this is a different definition of EEAR than used by ComEd; naming is coincidental).
P(f)	=	Probability that the system is constrained through one or more components (primary or secondary equipment) being out of service. This probability is a function of the performance of the plant. Note that the time that the component(s) is expected to be out of service is taken as a fraction of the total number of hours per annum and incorporated in the calculation of P(f). No correlation is assumed between outages (independent variables).

As mentioned in Section 2, EENS in its classical form is a generation adequacy measure that sometimes considers transmission system constraints. The definition provided in the TSPG is a bit ambiguous, but can be interpreted as follows:

- A “firm network” is N-1 secure; it is able to supply all demanded energy with any major piece of equipment out of service.

- Any energy demanded above a level by which the system is N-1 secure is defined as "energy at risk." For example, if loading in a particular hour is A, but the system is only secure when loaded to B, then the energy at risk for this hour is equal to A minus B.
- P(f) is the probability of a contingency occurring that results in operating constraints being violated.

Perhaps a better way to describe EENS in this context is to focus on contingencies rather than on EEAR. Consider a contingency, *c*, with probability of occurrence, $P_{c,h}$, during a particular hour, *h*. If this contingency occurs, constraints are violated until loading is reduced by an amount $EEAR_{c,h}$.

The total EENS can then be taken as the sum of all component EEAR values over all 8760 hours in a given year. In there are *N* contingencies considered in the analysis:

$$EENS = \sum_{h=1}^{8760} \sum_{c=1}^{N} P_{c,h} EEAR_{c,h}$$

It is assumed that this is the intended meaning of EENS as described in the TSPG, and can be better thought of as the expected energy not served due to contingencies on the transmission system. Using this definition of EENS in the TSPG is a bit ambiguous since it implies that a "firm" system (N-1 secure at peak loading) has an EENS of zero. Since the TSPG suggests that the N-1 criteria are assumed to be economically justified, EENS should never be considered when making planning decisions.

This equation becomes much more powerful when the term "firm" is relaxed and higher order contingencies are considered. In this situation, even if the system is N-1 secure, multiple contingencies can still result in "energy at risk" and EENS will always be a positive value. It should be noted that EENS in its above form will work well as a probabilistic measure of transmission reliability for systems that are not N-1 secure, and this may be the intent of the TSPG.

3.4.3 Economic Criteria

The TSPG offers several economic criteria by which projects can be assessed. Each one is described and discussed in turn.

Net Present Value. This measure is simply the present value of all incremental revenue associated with a project (e.g., increased energy sales, reduced losses) less the present value of all costs (capital, operations, maintenance). If the net present value (NPV) is positive, the project should be selected since investors can be paid their expected returns. If NPV is negative, the project should be rejected since investors cannot be paid their expected returns. [Note: NPV is the correct measure to determine whether a discretionary project should be undertaken.]

Payback Period. This measure refers to the expected time that will elapse until accrued incremental revenue (undiscounted) exceeds accrued incremental costs (undiscounted). [Note: Although popular, payback period does not consider the time value of money and payback period is inappropriate to determine whether a discretionary project should be undertaken.]

Minimum Societal Cost. If NPV of a project is negative, the TSPG instructs that the project should still be undertaken if the benefit to customers exceeds the cost to the utility. Since benefits exceed costs, society as a whole should be better off.

4
FUTURE TRENDS

Exceptional forces are changing the use of the transmission infrastructure in the United States. There are high expectations that the transmission system will support and enable national-level economic, renewable energy, and other emerging policy issues. A large amount of transmission investment is expected, and this investment is largely intended to enable the transmission grid to efficiently perform functions for which it was not originally designed. Reliability metrics will inevitably be a large driver of these investments, and these metrics will be different than those used in the past.

In addition to expanded usage, regulatory oversight of the planning and operation of the United States electric grid is increasing. Transmission owners in the United States are under increasing scrutiny to plan and operate the system in a manner that ensures compliance with applicable standards created by NERC and approved by FERC. Proper utilization of leading indicator reliability metrics will be key to ensuring that transmission operators are in compliance with applicable standards.

4.1 Development of the North American Transmission System

The U.S. and Canadian transmission systems were developed in a piecemeal fashion. Originally, transmission systems connected large generation facilities in remote areas to users of the electricity they produced. Shortly thereafter, utilities started to interconnect their systems in order to realize the benefits of improved reliability that larger systems offer and to get access to lower-cost energy in other systems. Subsequent transmission lines were typically added incrementally to the network, primarily driven by the needs of the local utility and without wide area planning considerations.

Today, the transmission system is increasingly being called upon to serve as the platform to enable sophisticated and complex energy and financial transactions. New market systems have been developed that allow transactions interconnection-wide. Today, a utility can purchase power without knowing the seller. These same market systems will soon accommodate the ability of load-serving entities to bid in their loads.

As the barriers to participate in electricity markets start to disappear, the U.S. electric system starts to look small from the perspective of market participants. In his book of the same title [37], author Thomas Friedman states, “The world is flat.” That is, the location of producers and consumers no longer matters in the world. It is the expectation of wholesale electricity market participants that they can soon claim, “The transmission system is flat.” That is, the transmission system is such that the location of power producers and power purchasers does not matter in terms of participation in national electricity markets. Unfortunately, the vast majority of transmission infrastructure was not designed for this purpose. The existing transmission infrastructure is aging, and new transmission investment hasn’t kept pace with other development.

4.2 Goals of Transmission

When considering future trends of transmission reliability metrics, it is helpful to clearly articulate the goals of transmission systems today. Of course, the primary function of transmission is to transport bulk power from sources of desirable generation to bulk power delivery points. Historically transmission planning has been done by individual utilities with a focus on local benefits. However, proponents of nationwide transmission policies now view the transmission system as an "enabler" of energy policy objectives at even the national level. This is an understandable expectation since a well-planned transmission grid has the potential to enable the following non-traditional goals:

<u>Non-Traditional Goals of the North American Transmission System</u>

- **Supporting efficient bulk power markets.** Bulk power purchasers should almost always be able to purchase from the lowest-cost generation. Today, purchasers are often forced to buy higher-cost electricity to avoid violating transmission loading constraints. The difference between the actual price of electricity at the point of consumption and the lowest price on the grid is called the "congestion" cost.
- **Providing a hedge against generation outages.** The transmission system should typically allow access to alternative economic energy sources to replace lost resources. This is especially critical when long-term, unplanned outages of large generation units occur.
- **Providing a hedge against fuel price changes.** The transmission system should allow purchasers to economically access generation from diversified fuel resources as a hedge against fuel disruptions that may occur from strikes, natural disasters, rail interruptions, or natural fuel price variation.
- **Ensuring low-cost access to renewable energy.** Many areas suitable for producing electricity from renewable resources are not near transmission with spare capacity. The transmission system should usually allow developers to build renewable sources of energy without the need for expensive transmission upgrades.
- **Maintaining operational flexibility.** The transmission system should allow for the economic scheduling of maintenance outages. It should also allow for the economic reconfiguration of the grid when unforeseen events occur.

When considering transmission reliability metrics, care should be given so that metrics being developed adequately consider these goals as well.

4.3 Changing Regulatory Environment

As utility managers consider the use of metrics for measuring the performance of their systems, recent changes in the regulatory environment should be considered.

4.3.1 FERC Order 890

Since the advent of open access in 1996, FERC has pushed for information regarding the transmission system to be open and public.

As of the time of the writing of this report, the most recent FERC action in this regard has been the February 16, 2007, issuance of FERC Order 890 [31]. A few aspects of Order 890 should be of interest to readers of this report.

One metric described in this report is Available Transmission Capacity (ATC), which is also specifically addressed in FERC Order 890. In Order 888, FERC required that ATC values and the methodology used to calculate this metric be posted to all users of the transmission system. However, in Order 890, FERC clearly established a requirement that all published ATC and AFC values be derived in a manner that produces "consistent" and "equivalent" results.

Further, Order 890 required that each transmission provider's Attachment C to its open access tariff be updated to include a detailed formula for the calculation of firm and non-firm ATC.

One advantage of this requirement is that it creates the possibility for utility managers to benchmark system capability in order to compare investment levels over time with forecasted – and published – increases in ATC.

In addition to the requirements regarding comparable and equivalent ATC, FERC also imposed new requirements on transmission planning processes. Of interest to readers of this report is the section on Economic Planning. FERC required economic planning studies to be conducted to determine

1. the location and magnitude of the congestion;
2. possible remedies for the elimination of the congestion, in whole or in part;
3. the associated costs of congestions;
4. the cost associated with relieving congestion through system enhancements.

In Section 20, FERC specifically discusses the use of metrics. First, FERC clearly states that metrics should not be used to automatically trigger congestion studies (e.g., zero ATC or TLR frequency). FERC's concern in this regard is that a metric-driven trigger for automatic congestion analysis may result in undue costs for conducting unnecessary studies.

However, FERC also clearly states transmission providers should be obligated to study the cost of congestion, when they have the ability to do so. In this regard, transmission providers are directed to update their Attachment K to describe how studies are being clustered and they are directed to post the results of their studies on the OASIS. As a result, significant information will soon become available regarding methods for calculating congestion costs in energy markets and benchmarking system performance against peer systems.

4.3.2 ERO Mandatory Compliance

In 2005, President George W. Bush signed the Energy Policy Act into law. This act created the Electric Reliability Organization (ERO). In 2006, the North American Electric Reliability Corporation (NERC) was designated as the ERO for the U.S. electric industry by FERC.

As part of the creation of the ERO, operating and planning standards — which had previously been voluntary — have become mandatory. In addition, and very relevant to utility managers, non-compliance with these standards is closely monitored by NERC (acting as FERC-designated ERO). NERC performs this duty by working the regions through delegation agreements. Entities found non-compliant with the standards are subject to a variety of sanctions, including monetary fines.

As a result of this relatively recent development, this report identifies metrics that allow utility management to track their organizations' compliance performance.

4.4 Transmission Reliability Today

As the transmission system becomes flatter, the processes to analyze and achieve objectives on a regional or interconnection-wide basis have lagged. Utility-centric planning processes simply do not have the reliability metrics or perspective necessary to keep pace with the scope of the economic and policy objectives being faced today. While the planners of transmission often recognize these needs, addressing these needs exceeds the scope of their position. Regional transmission organizations exist today, but these organizations are struggling with the need to begin to develop plans spanning multiple regions to satisfy interconnection-wide objectives.

4.4.1 Paradigm Shift

The main technical criteria that should drive transmission planning are reliability and congestion. Reliability relates to unexpected transmission contingencies (such as faults) and the ability of the system to respond to these contingencies without interrupting load or violating operating constraints. Congestion occurs when transmission reliability limitations result in the need to use higher-cost generation than would be the case without any reliability constraints. Both reliability and congestion are of critical importance and present difficult technical challenges.

For decades, the primary transmission reliability consideration has been N-1. N-1 has served the industry well, but has several challenges when asked to satisfy future needs. The first is its deterministic nature; all contingencies are treated equally regardless of how likely they are to occur or the severity of potential consequences. The second, and more insidious, is the inability of N-1 (and N-2) to account for the increased risk associated with a more heavily interconnected system and a more heavily loaded system.

When a system is able to withstand any single major contingency, it is termed *N-1 secure*. For a moderately loaded N-1 secure system, most single contingencies can be handled even if the system response to the contingency is not perfect. When many components of a transmission system are operated close to their thermal or stability limits, a single contingency can significantly stress the system and can lead to problems unless all protection systems and remedial actions operate perfectly. In this sense, moderately loaded systems are "resilient" and can often absorb multiple contingencies and/or cascading events. Heavily loaded systems are "brittle" and run the risk of widespread outages if an initiating event is followed by a protection system failure or a mistake in remedial actions. Since blackouts invariably involve multiple contingencies and/or cascading events, N-1 and N-2 are not able to effectively plan for wide-area events.

N-1 secure systems are, by design, not able to withstand certain multiple contingencies. When equipment failure rates are low, this is a minor problem. When equipment failure rates increase due to aging and higher loading, this problem becomes salient. Consider the likelihood of two pieces of equipment experiencing outages that overlap. If the outages are independent, the probability of overlap increases with the square of outage rate. Similarly, the probability of three outages overlapping (exceeding N-2) increases with the cube of outage rate. Blackouts typically result from three or more simultaneous contingencies. If transmission failure rates double due to aging and higher loading, the likelihood of a third-order event increases by a factor of eight or more. Today's transmission systems may remain N-1 or N-2 secure, but the risk of wide area events is much higher than a decade ago.

In addition to reliability planning, it is becoming increasingly important to plan for congestion (the 2006 Department of Energy congestion study reports that two constraints alone in PJM resulted in congestion costs totaling $1.2 billion in 2005 [21]). Basic congestion planning tools work as follows. First, hourly loads for an entire year are assigned to each bulk power delivery point. Second, a load flow is performed for each hour (accounting for scheduled generation and transmission maintenance). If transmission reliability criteria are violated, remedial actions such as generation re-dispatch is performed until the constraints are relieved. The additional energy costs resulting from these remedial actions is assigned to congestion cost (sophisticated tools will also incorporate generation bidding strategies and customer demand curves). Each case examined in a congestion study is computationally intensive.

There are many ways to address existing congestion problems, but it is difficult from a technical perspective to combine congestion planning with reliability planning. Imagine a tool with the capability to compute both the reliability and congestion characteristics of a system. A congestion simulation is still required, but unplanned contingencies must now be considered. To do this, each transmission component is checked in each hour of the simulation to see if a random failure occurs. If so, this component is removed from the system until it is repaired, potentially resulting in increased congestion costs. Since each simulated year will only consider a few random transmission failures, many years must be simulated (typically one thousand or more) for each case under consideration. These types of tools are useful when only the existing transmission system is of interest, such as for energy traders or for dealing with existing congestion problems. For transmission planners that need to consider many scenarios and many project alternatives, these types of tools are insufficient at this time.

Perhaps the biggest technical challenge for future transmission reliability metrics is to overcome the traditional mindset surrounding transmission planning. Traditionally, a planning was primarily concerned with the transport of bulk generation to load centers without violation of local constraints. In today's environment, effective transmission planning requires a wide-area perspective, aging infrastructure awareness, a willingness to coordinate extensively, an economic mindset, and an ability to effectively integrate new technologies with traditional approaches.

4.4.2 Regional Operators/Planners

It is difficult to address reliability across a wide area or the whole interconnected system. Reliability is biased by the existing transmission topology and ownership boundaries, designed many years ago for the vertically integrated utility industry. Long-range planning, such as that being performed by regional planning entities, requires a process that can address wide-area reliability weaknesses and consider alternative topologies beyond the existing ownership boundaries to facilitate future needs of improving reliability and transporting power across large regional markets. Increasingly, regional planning entities want to develop long-range plans that serve as a true blue print for the future. Proactive long-range planning processes are developing that look 15 to 20 years into the future.

However, the option to consider a very large number of new transmission connections adds complexity to the planning and selection process. Suppose *n* substations are candidates for new transmission connections. The number of possible new transmission lines is given by:

$$\frac{n!}{(n-2)!2!}$$

Evaluating the impacts of such a large number of transmission connections requires metrics for efficiently screening alternatives to determine which ones have the most promise to deliver the most cost-effective benefits.

4.4.3 Expanding Markets

Currently there are eight energy markets established in the United States and Canada. These include:

- PJM
- NYISO
- ISO NE
- MISO
- Cal ISO
- ERCOT
- IESO (Independent Electricity System Operator, Ontario, Canada)
- AESO (Alberta Electric System Operator, Alberta, Canada)

As markets expand and allow for trading across the borders, transmission owners and operators are no longer able to control who uses their transmission system. Expanding markets make it especially difficult to predict where congestion will occur and, therefore, to plan for. In this regard, information such as *congestion cost*, *congestion revenue*, and transmission shadow prices generated from security-constrained dispatch algorithms provide vital signals for a network expansion algorithm. The network should be planned and expanded not to exceed an "acceptable level" of congestion in the network over the planning period based on the balance between the congestion-cost savings and the network expansion investment cost to alleviate such congestion. Efforts have been made and preliminary results have been reported in both industry and academic communities [34][26].

At the same time, the energy markets are expected to expand in a way that provides a robust transmission network which provides a hedge against all uncertainties, including un-forecasted load growth, increasing fuel prices, available generation capabilities, unpredictable combinations of transmission facility outages, and expansion of energy/capacity markets. With all these uncertainties the market's expansion faces great risks. Since risk assessment is characteristically based on probabilistic and stochastic methods, probabilistic should be developed for transmission planning in the deregulated electricity markets [27]. It has also been proposed to use physical transmission rights (PTRs) and financial transmission rights (FTRs) as a long-term means for dealing with congestion under various uncertainties [28].

4.4.4 Workforce Challenges

The challenges of planning and operating the North American electric system continue to increase while the workforce size is constrained. Compounding the challenges is a widely documented talent drain in the industry [24] due to an aging workforce and retirements of key staff. Tools and associated metrics are now emerging which are designed to enhance workforce efficiency.

4.4.5 Aging Transmission System

The industry is planning to aggressively expand the existing transmission system to address new transmission requirements. At the same time, much of the existing transmission system is approaching the end of its useful life and will have to be rejuvenated or replaced. This has several implications. First, can transmission reliability metrics fairly compare new infrastructure projects with aging infrastructure projects? Second, can reliability metrics capture potential interactions so that new construction and aging infrastructure projects can work together in pursuit of common goals? For example, old transmission equipment is typically replaced like-for-like, but other approaches could defer or reduce the need for new construction.

For the past 20 years, the growth of electricity demand has far outpaced the growth of transmission capacity. With limited new transmission capacity available, the loading of existing transmission lines has dramatically increased (see Figure 4-1). Deterministic NERC reliability criteria have still been maintained for the most part, but the transmission system is far more vulnerable to multiple contingencies and cascading events.

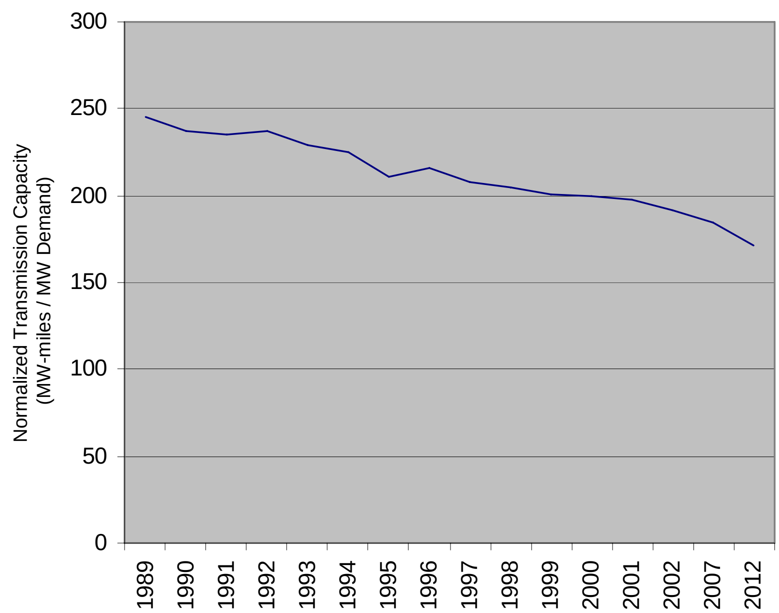

Figure 4-1
Transmission Capacity Normalized over MW Demand[1]

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[1] E. Hurst, *U.S. Transmission Capacity: Present Status and Future Prospects*, Prepared for EEI and DOE, August 2004.

A large percentage of transmission equipment was installed in the post-war period between the mid-1950s and the mid-1970s, with limited construction in the past 20 years. The equipment installed in the post-war period is now between 30 and 50 years old, and is at the end of its expected life. Having a large amount of old and aging equipment typically results in higher probabilities of failure, higher maintenance costs, and higher replacement costs. Aging equipment will eventually have to be replaced, and this replacement should be planned and coordinated with capacity additions.

According to Fitch Ratings [36], 70% of transmission lines and power transformers in the United States are at least 25 years old. Their report also states that 60% of high-voltage circuit breakers are at least 30 years old. It is this aging infrastructure that is being asked to bear the burden of increased market activity and to support policy developments such as massive wind farm deployment.

As a result, it is critical that new transmission construction be planned well, so that the existing grid can be systematically transformed into a desired future state rather than becoming a patchwork of incremental decisions and uncoordinated projects. To effectively manage this issue, asset management methods and metrics used by many utilities for managing distribution investment will need to be expanded into the transmission realm.

4.5 Directions for Future Metrics

The crystal ball is cloudy when it comes to the future of transmission reliability metrics. However, it is clear that there are two ultimate issues of primary concern. These are (1) the price that end users pay for electricity, and (2) the reliability seen by end users. Focusing on end users serves as a guiding compass when deciding the best course to pursue with respect to transmission reliability metrics.

4.5.1 Evolving Currently Used Metrics

4.5.1.1 Example 1: Modifying SAIDI and SAIFI Metrics

One pathway to expand well-understood distribution asset management processes into transmission usage is by decoupling the components that make up the distribution reliability indices such as SAIFI and SAIDI. SAIFI is a measure of how many sustained interruptions an average customer will experience over the course of a year. SAIDI is a measure of how many interruption hours an average customer will experience over the course of a year. Formulae for SAIFI and SAIDI are:

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}} \qquad \text{/yr}$$

$$\text{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customers Served}} \qquad \text{hr/yr}$$

Typically, transmission contingencies only contribute between 5% and 10% of SAIDI. For a typical utility with a SAIDI of 120 min/yr, transmission outages will typically contribute from 6 min/yr to 12 min/yr. A similar amount is typically due to distribution substation outages. From this perspective, it is straightforward to decouple SAIDI into three components: transmission ($SAIDI_T$), distribution substations ($SAIDI_S$), and distribution ($SAIDI_D$):

$$SAIDI = SAIDI_T + SAIDI_S + SAIDI_D$$

It is possible to take the same approach with SAIFI, but SAIDI considers both frequency and duration effects and is generally considered a good single measure of average customer reliability.

Since most transmission systems are built to N-1, any single contingency will not result in any customer interruptions. Therefore, the calculation of $SAIDI_T$ must necessarily look at N-2 contingencies for N-1 systems and N-3 contingencies for N-2 systems. The analysis should also consider other situations that commonly contribute to $SAIDI_T$ such as protection system misoperation and cascading failures leading to widespread blackouts.

The combination of %C and $SAIDI_T$ gives a good probabilistic description of transmission reliability from the customer perspective. %C is indicative of how transmission reliability will impact the cost of energy. $SAIDI_T$ is indicative of how transmission reliability contributes to overall SAIDI performance of a utility. There are many other measures being proposed, each with their own merit, but it is always advisable to keep reliability measures as close to the customer experience as possible.

4.5.1.2 Example 2: Normalizing Existing Data

Price impact is best handled through congestion cost. A normalized metric is desired so that transmission systems of varying sizes can be compared. This is easily done by dividing congestion cost by the cost of energy without any congestion. This approach results in the following formula for percent congestion (%C):

$$\%C = \left(\frac{Cost\ of\ Energy\ with\ Congestion}{Cost\ of\ Energy\ without\ Congestion} - 1 \right) \times 100$$

For %C to reflect issues related to transmission reliability, it is critical for congestion costs to include the impact of unplanned outages. To do this, Monte Carlo simulations are typically required. These algorithms sequentially model each hour within a year and scheduled outages throughout the year. For each hour, the simulation also checks to see whether a piece of equipment fails. If a piece of equipment fails, it is removed from the power flow model with the possibility of increasing congestion cost for the duration of the outage. Congestion models using Monte Carlo simulations are commercially available.

As indicated previously, there are no standard metrics for measuring congestion and its impacts. The metrics listed above were all developed specifically for a single market or a specific study. As with most tools, they are subject to future refinement. Further dialogue with the industry, regional transmission planners, market monitors, and the academic community will be helpful. There are some critical issues that need immediate attention, including:

- Modeling improvement --- One of the important technical challenges to congestion modeling is that the current DC models do not address voltage problems. Separate analysis with an AC model is required to ensure that voltage and transient stability are properly addressed. As a related issue, more work is needed to effectively model marginal rather than average transmission system losses to more closely parallel actual system physics.

Much of the congestion seen today results from the practice of adhering to reliability limits imposed so as to be prepared to withstand contingencies. Some congestion is due to scheduling practices and transmission rights rather than reliability and operational capabilities. Thus, the complex relationship between contingencies and congestion needs to be more fully understood

4.5.2 Data Mining Publicly Available Information

More and more information is becoming available to allow for a comparison of key information.

4.5.2.1 Example 1: Regional Planning Information

There are currently nine regional transmission organizations (RTOs) organized throughout North America. These RTOs oversee the coordinated operation of the electric systems within their footprint. They collect and provide detailed information regarding the current status of their member transmission systems. They also serve as transmission providers, coordinating the provision of transmission service for customers moving electricity and capacity into, through, and out of their footprints. Most of these organizations also perform regional coordinated transmission planning. Those that provide this service publish multi-year transmission plans, in some instances extending out as far as 20 years.

Figure 4-2 shows a list of the established regional transmission operators in the United States and Canada.

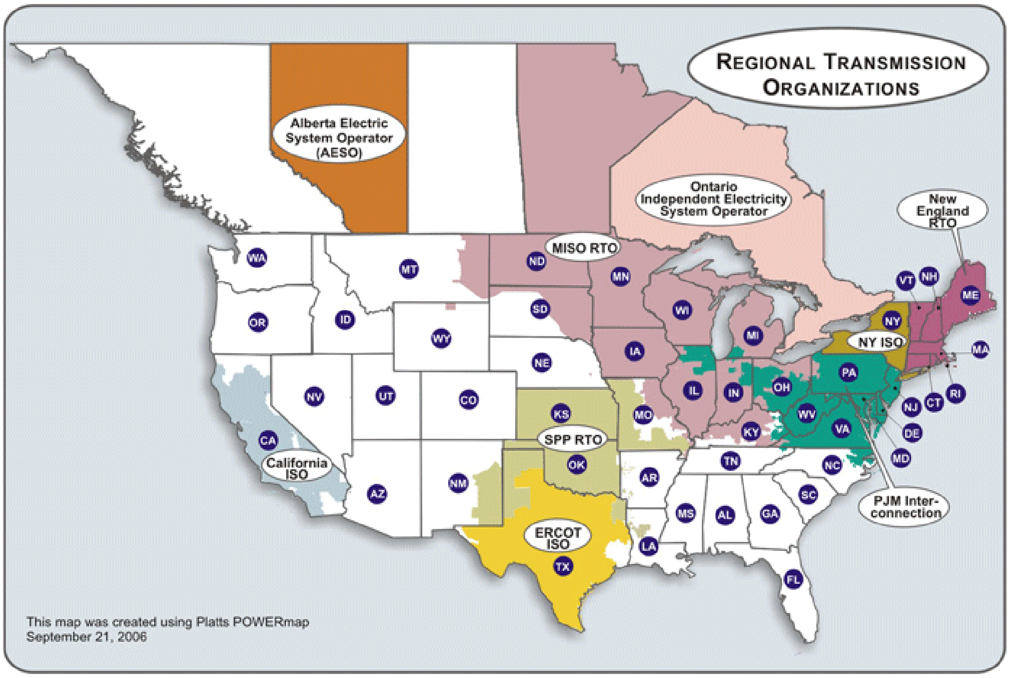

Figure 4-2
Regional Transmission Organizations in the United States

A wealth of information is available in the transmission plans of these ISOs. Plans may be found at the following locations:

http://www.aeso.ca/transmission/8635.html

http://www.spp.org/section.asp?group=1155&pageID=27

http://www.pjm.com/planning/reg-trans-exp-plan.html

http://www.caiso.com/1f75/1f75d5ea40bd0.html

http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2007_RNA.pdf

http://www.midwestiso.org/page/Expansion+Planning

http://www.iso-ne.com/trans/rsp/index.html

4.5.2.2 Example 2: Compliance Performance

Additionally, NERC is committed to publishing detailed information regarding standards compliance. Information is now available on standards violations by region, by standard, and, if one searches the audit reports, even by requirement. The following link shows the most recent information regarding NERC compliance status for the registered entities in the United States and Canada.

http://www.nerc.com/~filez/enforcement/index.html

4.5.3 Expanding Use of Hybrid Metrics

The WFLR metric described above shows promise for use by utility mangers to help sort through other challenging planning situations as well. Examples cited in [12] include:

1. Planners are presented with unfamiliar or unexpected system conditions. In this case the WFLR and the underlying AMVACO metrics can be used to highlight problem areas and generate new ideas for further evaluation.
2. Utilities are faced with limited planning resources. In this case engineering managers can employ the WFLR and the underlying AMVACO metrics to enhance productivity by increasing the number of project alternatives to be considered for further development.
3. Planners are optimizing project packages. In this case planners can evaluate different project termination points by comparing the AMVACO values for the various terminations.
4. Utilities are faced with limited capital budgets. In this case planning mangers can use the WFLR and the underlying AMVACO metrics to evaluate candidate projects to remove by screening and ranking the CSR values of each project being proposed.

4.5.4 Standardizing Data and Methodologies

The industry continues to move toward standardized data and methods. FERC Order 890 requires transmission providers to follow a FERC approved methodology for calculating key values such as TTC, ETC, AFC, TRM and CBM. In addition, FERC has required transmission utilities to file these methodologies in updated Attachment C to the OATT. Along with the requirement to file information regarding Economic Planning studies in updated Attachment K, these actions will result in a more consistent set of publicly available information that utilities can use to compare their system's performance with industry data.

4.5.5 Increased Utilization of Benchmarking

As transmission information becomes standardized and information is published in public forums such as OASIS, ISO websites and plans, and others, the ability to benchmark performance of utility systems will be greatly expanded.

As an example, utility capital spending patterns will be available from the regional planning documents. Using OASIS data, this capital spending can be analyzed with the comparable improvements in congestion via ATC, ETC, or AFC postings.

With the publishing of the compliance violation data, company compliance performance compared with peers can be readily checked. Normalization via company size, circuit miles, system type, and number of employees, will add additional insights for utility management.

5
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