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**IDENTIFICATION, DEFINITION AND EVALUATION
OF
POTENTIAL IMPACTS FACING THE U.S. ELECTRIC
UTILITY INDUSTRY OVER THE NEXT DECADE**

Final Report

Research Work

for

**Los Alamos National Laboratory
Los Alamos, NM**

by

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EXECUTIVE SUMMARY

Our nation's infrastructure for delivering electric power is approaching its capacity. Due to environmental, economic, and many other concerns, cancellation or delay of the scheduled construction of new generation and transmission systems needed to meet the nation's increasing electricity demand is occurring with increasing frequency. As a result, transmission systems are loaded close to their limits in many parts of the country, and the controllable margins of the generation reserve capacity are decreasing to a level that threatens system reliability and security. A series of regulatory acts ranging from the Public Utilities Regulatory Policies Act in 1978 to the National Energy Policy Act of 1992 is further reforming the internal and external structures of the electric utility industry, and is changing the way the utility industry conducts business.

The integrity of the electric power delivery system is determined by its ability to supply electric power continuously. That integrity in turn, is determined by the manner in which the system is planned, how it is operated, and how it is controlled. Various technical, technological, physical, institutional, and financial issues could adversely affect the ability of the nation's electric utilities to continue to fulfill their missions. Numerous concerns and issues face the US electric utility industry today, including but not limited to:

- transmission access/retail wheeling
- non-utility generators and independent power producers
- design certification of standard nuclear power plants
- high-level and low-level nuclear-waste repositories
- industry restructuring/PUHCA reform
- integration of dispersed storage and generation into utility distribution systems
- long-term stability of natural gas prices
- EMF and right-of-way limitations
- Clean Air Act Amendments
- time-of-use and place-of-use pricing
- quality of power supply

The above issues have been examined to identify their likely impact on system reliability and security from the system operations viewpoint. It is noted that the reliability and security of power systems can be affected by various system design, configuration, and operating conditions. In particular, system reliability and security are considered to be adversely affected if the operating conditions and states of a power system exhibit one or more of the following attributes:

- instability (from the rotor angle standpoint)
- voltage instability
- abnormal steady-state operating conditions such as low voltage, transmission facility overload, frequency excursion, etc.

Of course, there are numerous conditions of the generation system that may ultimately develop into system states affecting system reliability and security. Therefore, such generation system conditions should also be considered when evaluating the potential impacts of the issues on system operations. Among the eleven issues listed above, the following five issues have been identified to impact system reliability and security to the greatest extent:

- Transmission access/retail wheeling
- Non-utility generators and independent power producers
- Integration of dispersed storage and generation into utility distribution systems
- EMF and right-of-way limitations
- Clean Air Act Amendments

Strictly speaking, some issues are interrelated and one issue cannot be completely dissociated from the others. However, this report addresses individual issues separately in order to determine all major aspects of bulk power system operations affected by each issue. The impacts of the five issues on power system reliability and security are summarized below.

Transmission access/retail wheeling involves transporting power from one location to another, usually via the lines of more than one owner. This aspect will necessarily complicate the control of power interchange among interconnected utilities. In the event that the number of entities requesting transmission access is numerous and access requests are not filed sufficiently in advance, accommodating them within the automatic generation control could become a burden to utility's system operators. Many problems associated with transmission access are related to the redistribution of power flows. In some cases, a change in the line flow pattern could alleviate existing overload problems. Arbitrary power injection and withdrawal resulting from open access will, however, tend to aggravate existing overload and low voltage problems to a much greater extent than it resolves them. Lack of reactive power support will decrease the power transfer capability especially over long or heavily-loaded transmission lines. Furthermore, protection coordination which is necessary to maintain system security cannot be ensured unless power suppliers who request open access have compatible protection designs.

Non-utility generators (NUGs) and independent power producers (IPPs) represent an increasing portion of utility's generation capacity additions. The majority of these generation sources are not under the control of the utility control center. It is the non-controllability of these generators that causes difficulty in system operation and control. Since NUGs and IPPs may be outside of a utility's load frequency control, the burden on the utility's central generators to maintain system frequency at the nominal value will become problematic if the total capacity from NUGs and IPPs is a significant part of the utility's generation capacity. NUGs and IPPs often run as base-load units. Therefore, generation from some of the utility's base-load units may have to back down to meet the generation-load balance. As a result, maintaining required operating reserve with adequate load-following capability will become difficult. In general, NUGs and IPPs lack reactive power support capability that is needed to maintain adequate system voltages. Shunt capacitors may be installed to provide required

VAR support. However, excessive use of shunt capacitors is likely to result in a system that is prone to voltage collapse. Here again, the protection schemes of the NUGs and IPPs should be compatible with that of the utility system to ensure adequate coordination. NUGs and IPPs could present safety hazards for utility service crews if they remain connected to a utility's isolated system.

Integration of dispersed storage and generation (DSG) into utility distribution systems may present numerous operation and control problems if the penetration level of DSG devices is high. Fault current calculations, relay settings, and protective device coordination have been traditionally designed based on the assumption that current flows only in one direction in a radial distribution feeder. With DSG devices installed on a feeder, this assumption is no longer valid. Small DSG devices installed near substations may be able to detect and respond to faults on adjacent feeders or on transmission systems. With DSG devices connected, multiple sources and multiple directions of flow of fault currents will upset existing protection coordination schemes. One of the primary reasons for discouraging high penetration of DSG devices on distribution feeders has been a dangerous rise in voltage at some nodes with a possible consequence of utility and customer equipment damage. Besides, reactive power requirements of DSG devices such as induction generators should be provided by the utility system. It is possible that line-independent generators can remain connected to a feeder even after the loss of utility supply. If an islanded mode of operation occurs, safety hazards and damage to the customer's equipment could be incurred. Since most DSG devices are likely to be beyond the control of utilities, stability and operability problems may also arise although the severity of the consequences is not evident at this point in time.

EMF concerns and right-of-way (ROW) limitations have been two major factors in utilities to delay or cancel many transmission line projects throughout the U.S. Utilities are operating transmission systems at their full capacities, a practice which will continuously reduce transmission system operating margin. Also to avoid long delay in getting necessary permits for acquiring new ROW, lines are often double-circuited to utilize the existing ROW. Consequently, inclement weather or accidents can cause greater disruption on transmission systems since a pole or tower failure will often be a double contingency event. The weakened transmission systems will be subject to steady-state and transient instability even under mild contingency conditions. Satisfying EMF restrictions can mean that some transmission lines cannot be loaded above certain limits. In this case, utilities may have to redispatch their generation to achieve such loadings, but it could overload their critical transmission lines or transformers. Undoubtedly, shortage of transmission lines due to EMF and ROW limitations will weaken transmission systems, and will adversely affect system reliability and security in general.

The Clean Air Act Amendments will force utilities to change their strategies for meeting customer demand while satisfying air quality standards. This gives rise to numerous operating problems which will directly and indirectly influence system reliability and security. To meet the emission standards, utilities may no longer be able to pursue economic dispatch of generating units. Generation from those units burning high sulfur coal may have to be

reduced drastically to lower emissions. Unit commitment schedules may also have to be altered to facilitate such constrained dispatch, which in turn will result in less responsive spinning reserve. The change in unit dispatch will necessarily alter power flows throughout utility transmission systems. This could result in transmission facility overloads for some critical lines and low voltage problems in the areas where plants may have to be shut down because of emission problems. Some utilities will attempt to import replacement power from other utilities to fill the shortage of generation caused by the shutdown of their polluting coal-fired plants. In some cases, the power transfer will load already heavily loaded tie lines beyond the safe limits, and will considerably reduce transmission capacity margins that are needed for maintaining system reliability and security.

This report examines the five critical issues that the U.S. electric utility industry will be facing over the next decade. The investigation of their impacts on utility system reliability and security is limited to the system operation viewpoint. Those five issues will undoubtedly influence various planning aspects of the bulk transmission system. However, those subjects are beyond the scope of this report. While the issues will also influence the restructure and business of the utility industry politically, sociologically, environmentally, and economically, all discussions included in the report are focused only on technical ramifications.

1. Introduction

The national security and economic well-being of the U.S. depends to an important extent on the adequacy and continuous availability of electric power supply because of its pivotal social and economic implications for the nation. Maintaining high degree of performance by the nation's electric power delivery system will require insightful and yet careful planning, flexible yet reliable operation and intelligent yet coordinated control - especially in view of the many serious challenges now facing the electric utility industry. The current and near-term issues confronting the nation's electric utility industry include, but are not limited to,

- industry restructuring
- transmission access
- retail wheeling
- non-utility generators (NUG's) and independent power producers (IPP's)
- EMF and right-of-way limitations
- increased use of existing transmission corridors
- transmission bottlenecks impacting transfer capability
- operability and flexibility of bulk power system
- design certification for standard nuclear power plants
- high-level and low-level nuclear waste repository site
- Clean Air Act Amendments
- long-term stability of natural gas price
- environmental constraints
- efficiency and competitiveness
- time-of-use and place-of-use pricing
- quality of power-supply signal
- industry deregulation

The uncertainties now associated with industry deregulation and restructuring are distracting electric utilities and causing them to delay decisions regarding new transmission lines needed for security and reliability enhancement. This is because the new competitive environment, which encourages breakdown and erosion of traditional service areas on the basis of local economics of supply, does not reward expenditures aimed at maintaining technical attributes such as global reliability and security of the bulk power system.

Ownership of generating resources has been traditionally concentrated in the vertically integrated electric utility within a defined geographic area, so that previously there was no division of responsibility or conflict of interest in planning the bulk-power transmission network on a regional reliability basis. Today there is no clear incentive for the investor owned utility to incur expenditures which could accommodate transmission access and possible retail wheeling by competitive neighbors or new suppliers entering the electricity supply industry. The obligation to ensure reliability and security of service is now developing a fuzzy distribution among all the players, traditional and new, in the power supply game.

Utilization and management of existing physical assets and resources are the focus of industry attention with the result that existing transmission corridors are being used for maximum power transfers and there is increasing interest in dynamic thermal ratings of transmission lines. The net result is that thermal capacity margins are diminishing which in turn is bound to constrain the flexibility, adaptability and responsiveness of the system especially in times of emergency. System reliability and security performance could easily suffer as more utilities forestall expenditures and so exhaust system margins and response flexibility - especially in view of the concurrent increase in demands for transmission access.

Recent natural disasters, such as the California earthquakes, the East Coast hurricanes, and the Midwestern tornadoes and ice storms, have demonstrated that some systems are not as resilient as they were a decade or so ago. There is growing basis for concern that this loss of resiliency may further erode power restoration options during future emergencies, to the detriment of system reliability and security from the customer's viewpoint.

Electric utilities today are in transition. Economic and other pressures, both external and internal, are at work recasting the way utilities conduct business. Regulatory changes are certain. Industry structure will continue to evolve as financial pressures dictate directions for generation, transmission and service to shifting customer bases. Open access and wholesale wheeling at the transmission level are a fact of life today while retail wheeling is at the heart of economic and regulatory issues now being debated. Both wholesale and retail wheeling will certainly and significantly alter the industry structure and traditional order of business.

Quite clearly, there are many differing perspectives on how the problems and issues facing the US electric utility industry will play out over the next decade. But there is little argument that the industry will change - its operations, its structure, and its capability to continue to deliver reliable and secure electric power to all customers.

2. Critical Issues Affecting System Reliability and Security

The integrity of the electric power delivery system is determined by the manner in which the system is planned, operated and controlled. Various issues of technical, technological, physical, institutional, regulatory and financial natures (currently impinging upon the traditional planning, operation and control functions) could adversely affect the ability of the national power delivery system to continue to fulfill its role. Among various issues that the US electric industry will be facing over the next decade, the most critical five issues that are capable of directly impacting system operations and thus system reliability and security have been identified as follows:

- Transmission access/Retail wheeling
- Non-utility generators (NUG's) and independent power producers (IPP's)
- Integration of dispersed storage and generation into utility distribution systems
- EMF and right-of-way limitations
- Clean Air Act Amendments

To evaluate the manners in which these issues will affect the reliability and security of the US power systems, reliability and security, as defined by the North American Electric Reliability Council, are described in the immediately following section. Discussion on attributes of power system operations and control affecting reliability and security follows in succeeding sections.

3. Reliability and Security Assessment

Reliability in a bulk electric system is, according to the North American Electric Reliability Council (NERC), defined to be the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. Reliability can be addressed by considering two basic and functional aspects of the bulk electric system - adequacy and security.

Adequacy is the ability of the bulk electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

Security is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Electric power systems are subject to disturbances at all times. Examples of such disturbances are sudden change in load demand, generator failure or transmission line outage due to faults. Therefore, adequacy is concerned with enough redundancy in generation and transmission capacities to take up the changes in loading caused by the disturbances, whereas security concerns enough controllable resources and mechanisms to steer the system to normal operation after the disturbances. Such robustness of the system relative to imminent disturbances in system operation is referred to as the security of the system, and the robustness of the system to a set of possible disturbances postulated in system planning is referred to as the reliability of the system.

3.1 Generation Adequacy

Traditionally, examining adequacy of power systems meant examining generation adequacy while bulk transmission system's aspects were ignored. The reason for that practice might be the fact that generation systems are capital intensive and that tools and methods are readily available to analyze generation system adequacy, but not for transmission systems.

All Regional Councils conduct the periodic assessment of the adequacy of generation within their Regions. A comprehensive assessment of adequacy requires an understanding of various parameters such as generating unit capacity and availability, projected in-service dates, cost and availability of fuel, demand growth and shape and its sensitivity to weather, etc. Probabilistic approaches to generation adequacy assessment have been used in virtually all Regions.

Assessment of the adequacy of generating capacity is normally carried out within capacity planning. Both deterministic and probabilistic procedures have been employed for analysis. Loss-of-load probability (LOLP) is the primary index used in probabilistic evaluation. LOLP calculations take into account load forecast uncertainty, planned and forced outages of

generating units, and capability of emergency import from outside systems, if available. In deterministic evaluations, the amount of installed generation reserve is used as a measure of generation adequacy.

Basically generating adequacy assessment deals with a combined analysis of demand and capacity. Undoubtedly the amount of installed generation capacity greatly impacts system reliability and security. However, the adequacy of generation capacity alone does not adequately describe the capability of generation systems under various operating conditions. For example, unless generators have sufficient load following capability, a system frequency excursion is likely to occur if load increases sharply or the system is experiencing abnormal conditions.

3.2 Assessment of Bulk Transmission Reliability

The reliability criteria for all Regional Reliability Councils of the NERC specify that the bulk electric systems shall be planned and operated so as to avoid widespread cascading power interruptions for the type of contingency events normally encountered on power systems, i.e., the more probable contingencies. Individual utilities have their own criteria for planning and designing their bulk power systems. Such criteria address the level of service reliability and specify the required system performance tests such as the loss of generators and/or transmission lines. Some Regions are not explicit in specifying criteria but suggest that member utilities use more probable contingencies in the design or testing of their bulk power systems. Other regions include in their criteria the system performance that should be met under the more probable contingencies.

It is not practical to test utility systems for all possible contingencies. However, it is worthwhile to examine a limited number of extreme contingencies in order to test the ability of systems to withstand severe events. Extreme contingencies may include loss of an entire generating station or transmission substation, loss of all transmission circuits on a common right-of-way, or loss of a major load center. Testing for extreme contingencies may reveal system weaknesses such as unacceptable bus voltages, heavy loading of equipment, and conditions that may lead to a widespread cascading outage.

Typical performance criteria require that loading on all facilities should remain within applicable emergency limits, and that no loss of load, system separation, or instability should result under any probable contingency conditions. Initiating disturbances often include three-phase faults with normal clearing or single line-to-ground faults with delayed clearing. Scheduled deliveries and receipts of interregional, intraregional, and transregional transfers may also be modeled in studies.

4. Attributes Affecting System Reliability and Security

The preceding section provides the framework for assessing system reliability and security by discussing reliability planning conducted within the NERC's Regional Reliability Councils. However, the reliability planning criteria discussed above does not reveal how system reliability and security would be affected by the critical issues identified in Section 2 of this report. To determine the conditions under which specific issues give rise to operating problems and what aspects of system security would be affected and how, those power system attributes that affect system reliability and security are now discussed below.

It is noted that the reliability and security of power systems can be affected by various system design, configuration, and operating conditions. In particular, system reliability and security are considered to be adversely affected if the operating conditions and states of a power system reveal one or more of the following attributes:

- instability (from the rotor angle standpoint)
- voltage instability
- abnormal steady-state operating conditions (low voltage, line and equipment overload, and frequency excursion)

In order to determine how the critical issues identified earlier would affect system reliability and security, we now examine how various aspects of system design, configuration, and loading conditions may lead to system conditions possessing the above three attributes.

Transient and Steady-state Stability

Power system stability may be defined as that property of the system which enables the synchronous machines of the system to respond to a disturbance from a normal operating condition and to return to a condition where their operation is again normal. Stability studies are usually classified into two types depending upon the nature and order of magnitude of the disturbance. These are *transient* and *steady-state stability* studies.

The *steady-state operating condition* of a power system is an operating condition in which all of the operating quantities that characterize it can be considered to be constant for the purpose of analysis. A power system is *steady-state stable* for a particular steady-state operating condition if, following any small disturbance, it reaches a steady-state operating condition which is identical or close to the pre-disturbance operating condition. This small-disturbance stability is sometimes called *dynamic stability*, for which the excitation system and turbine-governing system are represented in studies.

Transient stability studies are intended to determine whether the system will remain in synchronism following major disturbances such as transmission system faults, sudden load changes, loss of generating units, or line switching. A power system is *transiently stable* for a particular steady-state operating condition and for a particular disturbance if, following that

major disturbance, it reaches an acceptable steady-state operating condition.

The relative stability of a generating unit within a power system may be determined by two factors which can be used as guideline criteria. They are the angular swing of the machine during and following fault conditions and the critical clearing time. It is apparent that the inertia constant H of a generating unit and the transient reactance of the unit have a direct effect on both of these criteria. The H constant is defined as the ratio of the stored kinetic energy at synchronous speed in kilowatt seconds to machine rating in kilovolt-ampere. It is noted that the smaller the H constant, the larger the angular swing during faults. On the other hand, the maximum power that can be delivered decreases as the transient reactance of the machine increases.

When a fault occurs on a system, all bus voltages are reduced. At generator terminals the reduced voltages are sensed by the automatic voltage regulators which react to such voltage depressions and restore generator terminal voltages within the excitation system. This voltage boost is achieved by increasing the voltage applied to the field winding of the generator. This is, in fact, accomplished by the action of the amplifiers in the forward path of the voltage regulators. The initial rotor angle swing following the fault can then be reduced by the excitation system. Modern steam and electrohydraulic turbine governing systems have the ability to close turbine valves to suppress unit acceleration during severe system faults near the unit. Since single-phase faults are more prevalent than three-phase faults, relaying schemes, allowing independent or selective circuit-breaker pole operation, can be used to clear the faulted phase while keeping power on the unfaulted phases continue to flow, thereby extending the critical clearing time.

Although the control schemes described above are excellent control mechanisms to increase overall system stability, they are not likely to be affected by the issues to be examined in this report. However, it is noted that reducing the reactance of the system during fault conditions also enhances the possibility of maintaining stability. This aspect of system design strategies aimed at lowering system reactance will be most affected by some of the issues that will be evaluated in later sections.

Reducing the reactance of a transmission line is one way of raising the maximum power that can be delivered. Compensation for line reactance by series capacitors and increasing the number of parallel circuits between two points are frequent means of reducing reactance, thereby increasing stability margins. When parallel transmission circuits are available instead of a single circuit, some power is transferred over the remaining circuit even during a three-phase fault on one of the circuit as long as the fault does not occur at a paralleling bus. For other types of faults on one circuit, two circuits in parallel can transfer more power than a single faulted circuit. For more than two circuits in parallel the power transferred during the fault becomes even greater. Since accelerating power is obtained by subtracting power transferred from power input, increased power transferred during a fault means lower accelerating power for the machine and increased stability margin.

Voltage Stability

In some parts of North America, power transfer capability has usually been limited by transient stability. Recently, the voltage stability problem has begun to limit power transfers especially in western North America. As utilities are being forced to operate their system close to the thermal or steady-state stability limits, maintaining adequate system voltage has become a major concern for operators. *Voltage stability* is defined as the ability of a system to maintain voltage so that when load admittance is increased, load power will increase, and so that both power and voltage are controllable. *Voltage collapse* is the process by which voltage instability leads to loss of voltage in a significant part of the system. *Voltage security* is the ability of a system, not only to operate stably, but also to remain stable following any reasonably credible contingency or adverse system change.

Voltage instability is triggered by disturbance or change in system operating conditions requiring reactive power demand which is in excess of the system's capability. The inability of the system to provide the needed reactive power support is due mainly to intensive use of available generation and transmission systems. Considering that addition of any equipment is scrutinized today by most utilities to explore possible deferment, it is not surprising to see the growing phenomenon of voltage instability.

The reduced capacity margin problem mentioned above is compounded by increased use of shunt capacitors for reactive compensation. Excessive use of shunt capacitors to increase transfer limits is likely to result in a voltage collapse prone system. Since shunt capacitor reactive output decreases with the square of voltage, the capability of the capacitors to supply needed reactive power will be reduced as the critical voltage falls below the normal operating voltage range.

Voltage instability has been observed for different time frames ranging from seconds to tens of minutes. In general, it is classified into transient, classical, and long-term voltage stability according to three time frames.

The transient voltage stability time frame duration is normally up to ten seconds. Voltage instability is caused by unfavorable load such as induction motors and dc converters. Under low voltage conditions, the reactive power demand of induction motors will increase, contributing to voltage collapse. The action of load tap changers is not fast enough to cope with the transient voltage collapse phenomena associated with induction motor load. Dc links also weaken ac systems, causing voltage stability problems. During disturbances under stressed transmission loading conditions, western North America power systems have shown signs of voltage collapse tendencies.

Classical voltage stability is concerned with the time frame of one to five minutes. The terms "post-transient" or "mid-term" voltage stability have also been used. Load tap changers and distribution voltage regulators will react automatically to boost sagging customer voltage, but operator intervention is not possible during this time frame. A system may be transiently

stable. However, under the condition of large power import from remote generation, loss of large generators in the load area or loss of major transmission lines could cause large reactive power losses along with voltage sags at the load center. As load tap changers and distribution voltage regulators try to restore customer voltage, voltages on the transmission system further decrease. As a result, the generation and transmission system can no longer provide needed reactive power support, and the system collapses.

There have been several incidents that voltage deterioration occurred over twenty to thirty minutes. These phenomena are referred to as long-term voltage instability. During continuous load buildup, transmission lines and transformers may be overloaded, triggering breakers to trip the overloaded elements. In addition, load may lose diversity due to prolonged low voltage conditions. Under these circumstances following shorter time-frame voltage instability, long-term voltage instability may occur. During this time frame operator intervention such as load shedding is possible to avert voltage collapse.

Abnormal Steady-state Operating Conditions

Power systems should be designed with sufficient capacity within each area to serve area loads under various conditions. Design of power systems should also take account of providing capability to transfer power from one area to another. Transient stability of the interconnected systems should be maintained during and after the most severe probable disturbance. That aspect was discussed earlier. Operating conditions should also be maintained within steady-state limits. Conditions indicating abnormal operation are *low voltage, line and equipment overload, and low frequency*. In the case of overload, normal and emergency limits may be applicable prior to and following disturbances, respectively.

In technical terms, the power flow balance in steady state is governed by a set of equations called power flow equations. If the resulting power flows do not cause overload and abnormal voltages, the power flows are considered to be feasible. Power flow feasibility must be attained both at normal operation and at post contingency steady state. Line or transformer overload depends on the loading condition of the network, which in turn depends on the geographical distribution of generation and load centers in the system. In general, the higher the loading and the more separation of generation from the load centers, the higher the risk of overload.

Transmission systems do have loading limits. If the loading limits are exceeded, transmission lines can sag excessively or even burn down. Low voltage conditions in a local area that may not develop into voltage instability can still cause excessive reactive power flow in lines and equipment, thereby causing overload. Techniques for improving steady-state voltage include series compensation, shunt compensation, excitation systems, static VAR compensation, synchronous condensers, and transformer tap optimizations.

Each day, it is not uncommon to have some transmission lines out of service for scheduled maintenance. It is also not uncommon that a fault occurring on a transmission line develops

a short circuit that forces the line to be isolated. Transmission systems should be planned, designed, and operated with scheduled as well as forced (unscheduled) outages in mind.

A sustained frequency excursion is a sign of major generation-load unbalance. It is important for the trouble area to establish generation-load balance as soon as possible in order to restore frequency. This will enable any separated areas to be reparalleled so that the integrity of the entire system will be restored. Once the generation-deficient area is identified, load relief may be performed. In general, load relief is accomplished by reducing voltage or by load shedding or both.

In summary, power systems are constantly subject to various disturbances such as faults, loss of generation, etc. Depending on the severity of a disturbance and the state of the power system at the time of the disturbance, the system may experience detrimental conditions such as instability, voltage collapse, and abnormal operating conditions, in which case transition from secure state to insecure state occurs. The impact of the critical issues that the US utility industry will be facing could make the possibility of the system state transition from secure state to insecure state more likely and frequent. This transition of system state is depicted in Figure 4.1. In the next five sections, the five critical issues identified earlier will be discussed in the context of their impacts on system reliability and security.

Figure 4.1 Transition of system state under disturbances

5. Transmission Access/Retail Wheeling

5.1 Introduction

The transmission system not only links generating plants to load centers within a utility system but also links one utility's or area's system with neighboring systems via high voltage and/or extra high voltage interconnection tie lines. Through interconnected electric networks, it is possible to pool power plants to minimize the total generation capacity requirements to meet demand. Pooling the generation source is particularly beneficial if there is considerable diversity of load among the participating areas. Also the difference in fuel availability in different areas can be exploited for all participating utilities to reduce energy production costs.

Interconnections facilitate sale and purchase of power and energy between utilities. A utility may purchase power from neighboring utilities if the purchase price is lower than the cost to generate the needed power by its own generators. Utilities commonly exercise this type of economic purchase on a long-term and/or short-term basis. Besides the economic reasons, utilities also depend on interconnections during emergency conditions. In fact, interconnections can be viewed as standby generators in the event of unforeseen contingencies. Even spinning reserve can be shared between utilities through interconnections. For these reasons, interconnecting tie lines are seldom loaded up to their full ratings during normal operating conditions. Of course, the benefits of power pooling depend on the availability of capacity in neighboring areas and provisions of contracts in force.

Power transfers among utilities have been a fact of life since tie lines were first constructed to interconnect utilities. As the amount of power transferred over existing transmission corridors grow, the operation and control of the power system becomes increasingly complex. A number of operating problems ranging from transmission bottlenecks to voltage collapse have already been observed in several regions within the United States.

Transmission access and the wheeling of power through transmission systems is nothing new to the utility industry. Most of the electricity generated in the lower 48 states and in Canada is transmitted over four integrated bulk power networks. There are 153 separate power control areas representing either individual utility service areas or those of power pools. However, wheeling and transfers through these networks has been planned for with adequate capacity and control measures to ensure acceptable levels of security.

The security of the transmission systems becomes the unintentional victim of at least three recent federal act - Public Utilities Regulatory Policies Act (PURPA), the National Energy Policies Act (NEPA) and Clean Air Act Amendments (CAAA) of 1990. Unplanned and potentially unpredictable forced wheeling and access could result from

- Electric wholesale generators requesting wheeling under NEPA

- QF's producing under PURPA
- Wheeling from one air quality district to another to avoid CAAA 1990 violation.

Wheeling and transmission access becomes a concern when it is involuntary, unplanned for, or unpredictable. This concern has deepened following the passage of the National Energy Policies Act (NEPA) of 1992. Under this legislation, enforced through FERC, third party power producers may demand transmission access from a utility for wholesale wheeling. The retail wheeling issue is left up to the state.

Logically, costs incurred by the utility must be charged to the entity requesting wheeling. They should not be charged to the utility's customers, either through recovered expenses or through the rate base. However, the crux of the problem is that there is no simple way to assign responsibility of operating and maintaining electric transmission systems to all parties involved. This difficulty may be summarized as follows:

- Increased wheeling will increase the number of entities supplying energy to and drawing from the transmission system, which makes controlling the bulk power system more complicated and difficult.
- Sharing information among utilities and non-utilities is essential and has been done to secure operation of the interconnected bulk power systems. Transmission access places utilities and others in competition with each other. None of the parties to transmission access transactions will want to relinquish a competitive advantage. This reluctance resulting from transmission access and retail wheeling may discourage information exchange which is essential for reliability and security.
- However, the utility that owns the transmission system has the ultimate responsibility for the safe and reliable operation of the transmission system.
- Electric power follows the path of least impedance according to the laws of physics, not contract law. In other words, there is no practical way to provide a unique transmission path from the electricity supplier to a customer.
- The power transmission system is not a switching network such as telephone systems. Geographically-dispersed customers' electricity demand, which varies continuously, must be met without delay. Furthermore, power cannot be delivered to a consumer over a predetermined path.

The objective of enhancing efficiency of power supply through opening up the transmission grid to competitive power producers is conceptually simple to understand. However, it has several hidden problems. One is that retail customers who are unable to shop around the system should not be penalized. Another is that the integrity of the transmission grid must be maintained by all the responsible entities using the grid. Some have suggested that significant

access fee should be charged to those who are free to shop anywhere any time. In this way, costs of maintaining the reliability of the grid at an acceptable level can be recovered without undue burden on native load customers.

Open access may not be indiscriminate in providing opportunities to all parties involved. Retail customers could be at a disadvantage compared with wholesale customers such as large industrial customers and municipalities since retail customers will not have the market force to enable them to shop around as easily as wholesalers. Some have argued that a large wholesale customer who has shopped elsewhere should not be allowed to return without paying access fees which are adequate to maintain the quality or cost of service.

With open transmission access, utilities may be liable to gain monopoly benefits by using their transmission system in transporting others' power. In fact, utilities are burdened with the obligation to serve while others are free to enter or exit the transmission grid at their will. Since the bulk of utilities take the risks while third parties enjoy the benefits of open access environments, utilities have no incentive to build new transmission capacity.

In the past, it has been in the discretion of utilities that owned transmission facilities to determine who could access their transmission system and at what price. However, there is a need to reform the pricing policy for transmission use. The traditional notion of marginal cost pricing is no longer valid due to different definitions and measurements of marginal costs. Also marginal costs cannot reflect economies of scale in transmission. Sophisticated methods for pricing transmission services need to be developed to properly account for various problems caused by open transmission access.

Some think that access fees should be established to reflect (i) day-to-day dispatch and operation, (ii) required generating reserve that is based on long-run marginal costs including opportunity costs, and (iii) high fees needed to encourage corrective action by third party power producers. Pricing mechanisms should also recognize time and geographical differences. In other words, there may be price differences between peaks and off-peaks and at different locations. Furthermore, those transmission companies that agree to meet all long-term firm transmission services to qualified third parties may have to be allowed to price short-term transmission services flexibly. The importance of proper pricing policy cannot be overstated since any deficiency in pricing methods may encourage transmission access that is detrimental to security security.

There is also difficulty in planning. Customer's loads are essentially random variables. Therefore, even if coordinated studies are conducted among the utilities and the entities who pursue transmission access, it is impossible to predict all future operating conditions. In addition, unless requests for transmission access are made sufficiently in advance, certain operating problems cannot be foreseen during the planning stage. Long lead time of transmission facility construction makes the planning process more difficult.

The above discussion provides a rough outline of the impacts of transmission access on

planning and operation of the electric utility system. Open access to a transmission network for the purpose of delivering energy from one point to another imposes several unusual operating conditions on the electric power grid. Under extreme conditions, the grid may be totally incapable of delivering the desired power due to the following aspects of control, operation, and design problems:

- interchange control with many entities
- voltage stability
- transient stability
- compatibility of insulation design philosophies
- compatibility of protection design philosophies

At the very least, unanticipated operating conditions may be imposed on the network, which may require a technical reassessment of the established operating criteria for the grid. In what follows, we will discuss the various technical issues which must be explored in order to assess the impact of open access on the transmission network of an electric power system.

5.2 Interchange Control

The electric utilities in the US are already challenged by numerous control problems arising from a number of long-term, short-term and spot market power transactions among interconnected utilities. Nevertheless the US bulk power systems have been extremely reliable because all the transactions have been tightly controlled and regulated. Presently any transactions are scheduled by control areas which are able to monitor actual interchange flowing over the tie lines and to control generating units within individual control areas to meet scheduled interchanges.

Today, virtually every utility is interconnected to one or more neighboring utilities through tie lines. Utilities monitor the power flowing across interconnection lines to record power transactions for accounting purposes and to enable the energy control center to make any needed corrective actions in order to balance the area's total generation requirements.

The total load within a utility system varies continuously, and there is no way to directly measure the magnitude of the load. What is needed, therefore, is an indirect mechanism to determine the amount of generation needed to meet the system load. This mechanism can be provided by monitoring and analyzing tie-line power flows as well as any changes in system frequency. For example, if a utility observes that both system frequency and the net interchange leaving the system have decreased, it can be construed that a load increase has occurred inside the utility's system. In this case, the utility needs to increase its generation to satisfy the demand increase. On the other hand, if both system frequency and the net interchange leaving the system are observed to increase, a load increase outside the system can be concluded. Furthermore, the information on tie lines and system frequency reveals that the load increase has not been met by the outside utility whose load has increased, but by this utility. In this case, the utility would try to decrease their generation to the level that the total

tie-line flow returns to the scheduled value.

The difference between the total required generation and the actual total generation should be monitored continuously and corrected to ensure balance. The difference, which is considered to be a measure of the error, is called the *area control error* (ACE). ACE accounts for both the error in net interchange and the frequency deviation from the nominal value. The apportionment of the total required generation to individual generators is done by *automatic generation control* (AGC). The information needed to implement AGC includes tie-line flows, system frequency, and capability of generating units on line.

In general, non-utility generators do not follow the stringent operating guidelines adopted by virtually all electric utilities. By permitting access by numerous non-utility generators to the transmission system at their will, the number of transactions to be monitored will increase drastically, thus making a coordinated control of the interconnected bulk transmission system extremely difficult. In this case, each control area will not have complete information on the system states unless every non-utility generator is closely monitored.

Figure 5.1 Power purchase by a wholesale customer located within utility A from utility C

Transmission access by wholesale customers poses a particularly difficult problem in controlling tie-line flows. Suppose that a wholesale customer located within utility A plans to purchase power from utility C, as shown in Figure 5.1. In this case, the customer will have a purchase contract with utility C, and then needs to establish an agreement with utilities A and B for wheeling the power. Suppose further that the customer plans to meet his entire load by the purchase contract. The crux of the problem here is the fact that customer's load varies continuously. In other words, firm scheduled transactions between utilities A, B, and

C for wheeling the purchased power cannot do the job here. One way to execute the continuously-varying magnitude of transactions is to telemeter the customer's instantaneous demand to utilities A, B, and C, and to incorporate the information into each utility's instantaneous, say minute by minute, interchange schedule. Besides being costly, the difficulty of implementing this type of interchange scheme can be easily appreciated when considering transmission access request by many customers. In addition, if transmission access is truly open to anybody at any time, scheduling interchange will be a nightmare to energy control center personnel.

5.3 Voltage Stability

Transmission access involves wheeling power from one location (selling party) to another (purchasing party). In order to assess the impact of open access on transmission line flows, let us formally consider a power network shown in Figure 5.2, in which the seller is located at bus s and the buyer is at bus r . Suppose that the amount of power to be delivered to the buyer at bus r is P_c . As noted above, the electric power transmission network is different from the telephone switching network in that the generated power cannot be routed over a preselected path from the generating source to the consumer. In the power transmission network of Figure 5.2, the delivery of power may be depicted by a power injection into bus s and a withdrawal of the power at bus r . The actual pattern of power flow will then be determined by the law of physics. Since the power does not actually flow along the contract path, the resulting flows on a utility's transmission system are called the *loop flow* or *parallel flow*.

Figure 5.2 Wheeling of power from the generating source at bus s to the customer at bus r

Losses occur on electric power transmission networks, and therefore, it is necessary to input a generated power P_g at the source bus s , such that

$$P_g = P_c + P_L$$

where P_L is the incremental power lost in the network. The power lost is a complex function of the network topology and the prevailing load level in the base case. One could always determine the incremental power loss at a given operating point by solving a new network load flow, in which the load power at bus r is increased by P_c , and generator s is treated as a swing bus.

Alternatively, one could approximate the increased losses by a method similar to the B-coefficient method used in the traditional economic dispatch calculations. To represent the transmission-loss equation in terms of power output of the plants, two-stage approach can be taken. In the first stage, the system loss is determined in terms of only generator currents. In the second stage, the generator currents are transformed into the power outputs of the plants. The system loss P_l is then given by a quadratic equation in P_G expressed in the following matrix form:

$$P_l = P_G^T B' P_G + P_G^T B'' + B_0$$

where P_G is a column vector whose elements are the power plant outputs; matrices B' and B'' , and a scalar B_0 , which are commonly called the B-coefficients, are constants whose values are determined by the system impedances and configuration. The derivative of the above equation with respect to a plant output provides the incremental losses.

Yet another approximation is provided by the method of superposition (dc load flow), which is commonly used in power system contingency calculations. In this technique, it is assumed initially that the losses remain unchanged from the base case, and hence $P_c = P_g$. The power flow (or current flow) imposed by the new transfer requirement can be evaluated by generator shift factors. The incremental power flow imposed on any line, say line m - n , due to a transfer of P_c from bus s to bus r is given by

$$\Delta P_{mn} = S_{mn, sr} P_c$$

where the $S_{mn, sr}$ coefficient is the previously mentioned generation shift factor. This factor is a function of the network topology and impedances, and can be precomputed and stored for real-time use in a control center computer. The incremental loss can then be estimated by computing the losses in all the network elements ($\Delta I_{mn} \approx \Delta P_{mn}$ in per unit system)

$$P_L \approx \sum (I_{mn} + \Delta I_{mn})^2 r_{mn} \approx \sum 2 I_{mn} \Delta I_{mn} r_{mn}$$

where r_{mn} 's are the network element resistances and I_{mn} 's are current flows. The increased power loss is now to be supplied by the source. Indeed, this loss estimate is an underestimate,

because the redistribution of the reactive power has been omitted from the above discussion. Reactive power is a far more complex issue, and its most serious impact is on the voltage profile of the network.

A far more serious consequence of the redistribution of the power flow is the possible overloads on the network elements. The ΔI_{mn} calculated above must be superimposed upon the prevailing current in each network element mn to give the new current:

$$I'_{mn} = I_{mn} + \Delta I_{mn}$$

The new current in network elements must of course be within the operating capability of the element in order to maintain system security. If the number of transactions becomes large, the magnitude of additional current could be significant. Of course, the current in certain lines may decrease, but problems will be caused by those lines whose current increases. Thus, a most serious consequence of the new power flow which results from the open transmission access (i.e., many arbitrary superimposed generators and loads) is to cause unpredictable overloads. The unpredictability of overloads could be worsened during transmission line outage contingency conditions.

The technique described above to assess the real power flow redistribution is generally not suitable to determine the reactive power redistribution following the imposition of the open access transaction. This is due to the fact that the voltage regulated buses in the network change their own reactive power contribution as the network flows demand, as long as the reactive power sources at the regulated buses have sufficient capacity. In most power systems, the reactive power redistribution must be calculated by running a load flow as mentioned above. The reactive power adds reactive currents to the network elements, and the true network element currents are not the $\Delta I'_{mn}$ computed above, but complex incremental current phasors ($\Delta I'_{mn,r} + j\Delta I'_{mn,i}$) where the subscript r represents the real part of the phasor, and the subscript i represents the imaginary part caused by the redistribution of the reactive power. As mentioned previously, this imaginary part is responsible for the underestimate of the power loss P_L computed by the approximation of the dc load flow.

The increase in current flow in certain transmission lines caused by the open transmission access incurs much more additional reactive power losses in the transmission system. The problem of reactive power losses becomes worse particularly when it comes to long transmission lines. If the sources of the reactive power reach their operating limits in the new operating condition imposed on the network, the voltages in the network may sag, and other reactive sources must be called upon to furnish the needed reactive power. This will generally lead to much increased power losses, and unacceptable voltages on the network. This condition could eventually lead to voltage instability.

To illustrate the relationship between the power transfer capability of a transmission line and the line voltage, consider a simple example in which a load is supplied by a constant voltage source through a transmission line having a certain impedance. Shown in Figure 5.3 is a

family of p-v curves under three different power factor conditions, which simulate various conditions of reactive power losses on the transmission system. In the figure, p represents the magnitude of real power delivered to the load and v represents the voltage magnitude at the load. As can be seen for the case of the lagging power factor in the figure, as reactive power losses become increasing larger, the amount of real power that can be delivered to the load decreases considerably. Voltage collapse could also occur with a much smaller power transfer capability.

Figure 5.3 Power transferred to the load versus voltage

As the transmission system is opened to non-utility generators and wholesale/retail customers, the utilities need to provide greater power transfer capability to maintain the present-level reliability and security. However, as illustrated above, the open access would likely to cause transmission lines more heavily loaded, and incur much greater reactive power losses. This could result in voltage instability problems and much lower power transfer capability limits, which is in the opposite direction of the desirable system conditions.

On the other hand, since the customer loads must be supplied at voltage levels which are within the established limits, a depression in the transmission network voltage must be

corrected by the operation of voltage regulators, or switched capacitors, or both. In all of these cases, there will be the issue of the available margin for such additional control, as well as the greater wear on the operating mechanisms of such devices.

5.4 Transient Stability

Transient considerations are usually divided into two categories: electromagnetic transients, and electromechanical transients. Electromagnetic transients are a concern in the system design stage, and will be considered in the next section. Electromechanical transients are an operating concern. The traditional problem is that of transient stability of the power system at an operating point. As the open access policy is expected to create new operating states in the network, their impacts on the stability of the network must be assessed.

Open access will create new power flow patterns. As a result, it is natural that the stability margins of the power system will be altered from those in the base case. It is likely that in some cases the margins will be so reduced that acceptable operating contingencies will no longer be acceptable. For example, whereas the base case system may be stable for fault clearing in backup relay times, the system with new flow patterns may be unstable for this contingency. To maintain a level of security in the system with open access, one may be forced to operate the base case at a reduced transfer capability. This will certainly affect the overall economics of operation of the power grid.

Similar considerations hold for the case of voltage stability of the network, as discussed in the preceding section. This phenomenon has been observed in recent years over diverse power systems throughout the world. In all likelihood, electromechanical and voltage stability concerns have surfaced because the power systems are operating under reduced operating margins. It is to be expected that open access to the network will reduce these margins even further, and transient stability problems in the networks may be exacerbated in systems with open transmission access.

5.5 Compatibility of Insulation Design

One must assume that a power supplier who use the open access facility will have designed the interface equipment with adequate design margins. However, a modern power transmission network is designed with a finely graded insulating system, which reduces the risk of failures from over-voltages in power apparatus. The insulation design of various power system elements are graded (coordinated) appropriately, so that if need be, open air insulation systems will bear the brunt of any over-voltages, and will be allowed to fail before the power equipment is subjected to destructive over-voltages. If this finely engineered system is parallel with a subsystem that has not been designed with the same philosophy, it is conceivable that the power grid equipment will be placed in jeopardy. Issues of equipment and system insulation coordination must be examined with the greatest care in order to avoid creating unacceptable operating conditions.

5.6 Compatibility of Protection Design

Protection of power equipment and systems is also coordinated across the power system in order to achieve a dependable and secure protection system. This ensures that all faults are removed with certainty, and that only the faulted equipment or system is disconnected by the protection system. The coordination is generally through nested and interlocked zones of protection, as well as through nested operating times. It is absolutely essential that all protection systems on a contiguous network follow the same philosophy as to the dependability and security aspects. Also some protection settings are determined by the prevailing state of the power system and its contingencies. As has been pointed out earlier, generally the open access question brings up the possibility that a significant subsystem may be interconnected to the power grid. As in case of electromagnetic transient discussion, it is essential that the protection philosophy of the power grid be utilized by the designers of the open access subsystem. This would require a certain sophistication and familiarity with the prevailing protection system design practices, on the part of the parties availing themselves of the open access facility.

Yet another factor is the loadability of certain protection functions. The loadability is specified from considerations of operating contingencies of the base power system. As these will certainly change due to flows imposed by the open access transactions, it becomes necessary to examine the loadability issues of the existing protection systems. Of particular concern is the remote backup zones of step distance relays, fault detectors, carrier start relay settings, out-of-step relay settings, and loss-of-field relay settings. All of these must be carefully examined in light of the anticipated flow patterns resulting from the open access transactions, in order to maintain the quality of the protection functions provided.

Figure 5.4 illustrates the principle of interlocking zones of protection. Each of the power system elements, such as transmission lines, transformers, buses, generators, etc. are protected by protection equipment which responds to faults within its zone of protection. The zones of protection are shown by dotted lines in Figure 5.4. Note that the zones overlap (generally around a circuit breaker), so that no part of a power system is left unprotected. Also, the region of overlap is made as small as possible, so that there are relatively few faults inside the region of overlap, which would lead to interruption of equipment within the two overlapping zones of protection. Further, the protection system is designed to provide backup function in the event a main protection function fails to perform normally for any reason. This is achieved by giving the surrounding protective devices the capability to respond to faults whose protection system has malfunctioned. This type of operation is done by the use of time delays, known as coordination delays. The delays ensure that the primary protection is given sufficient time to operate, if it is going to operate correctly. The delayed response of the backup devices is of course not the most desirable mode of operation, as it keeps the fault on the system for a longer time, and when it operates, usually removes a greater portion of the power system from service than is really necessary.

Often, several backup protection systems are provided to allow for second and third

contingencies. Thus, the primary protection of zone A (see Figure 5.5) is backed up by the first backup system with zone B, which in turn may be backed up by the second backup system with zone C. The three zones are nested in the spatial dimension as shown in Figure 5.5. This is known as coordination by distance. As explained before, the backup systems are progressively slower, thus they are also nested (coordinated) by their operating times. The coordination by distance, and by time is well illustrated by the step-distance protection function of a transmission line as shown in Figure 5.6.

Figure 5.4 Interlocking zones of protection

Figure 5.5 Protection coordination by distance

Figure 5.6 Coordination by time and distance

As has been pointed out earlier, generally the open access question brings up the possibility that a significant subsystem belonging to the supplier of open access power may be interconnected to the power grid. If a portion of the power system has inappropriate zone nesting, or is time-coordinated incorrectly, it is likely to lead to slower fault clearing in many cases, and may lead to unnecessary tripping. As in case of electromagnetic transient discussion, it is essential that the protection philosophy of the power grid be adhered to by the designers of the open access subsystem. This would require a certain sophistication, and familiarity with the prevailing protection system design practices, on the part of the parties availing themselves of the open access facility.

Impedance relays are another example where open access transmission may create some problems. It is well to review the principle of stepped distance relaying through impedance relays, as they are the most prevalent form of protection used on modern transmission networks, and they often define operating limits such as loadability, loss-of-field condition, as well as out-of-step conditions. The distance relay characteristic is commonly shown as a region (zone) in the complex R-X plane. The apparent impedance seen by a relay is $Z_{app} = E/I$, where E and I are the appropriate relaying voltage and current. The apparent impedance is separated into its real and imaginary parts, to provide the apparent R,X pair seen by the relay at any given time. If the R,X pairs fall within the relay zone of protection, the relay takes appropriate action, such as tripping, or tripping with a time delay, or initiating or blocking carrier, etc. Consider the zone of a distance relay shown in Figure 5.7. Although

the zone shown here is a circle, the discussion is valid for any other shape in use. The boundary of the zone defines the values of R, X pairs, which would just make the relay operate. As each value of the apparent impedance corresponds to a certain load level, a zone boundary provides a locus of allowable loads which the transmission system can carry, without causing a relay trip. If load powers are greater than those on the boundary of the zone, the corresponding R, X values will be smaller, and will be beyond the loadability limit imposed by the relay. The largest zones in the R, X plane have the lowest loadability limit, and hence define the loadability limit of the complete protection system.

Figure 5.7 Impedance relay

Loss-of-field and out-of-step relays are also impedance type relays. Loss-of-field relays are placed at the terminals of generators. A typical loss-of-field characteristic is shown in Figure 5.8(a). The loss-of-field condition is inferred when the apparent impedance enters the zone of the relay, and may cause a trip, or send an alarm. The out-of-step relays use a set of blinders as shown in Figure 5.8(b), in order to detect the stability swing, and take blocking or tripping action at appropriate places when an unstable swing is detected. The zone settings, as well as the timer settings are determined with the help of numerous transient stability studies.

Figure 5.8 Loss-of-field and out-of-step relays

It should be noted that settings of all the distance relays mentioned above are predicated upon certain system maximum loads, and all likely contingencies for which the system is to function securely. The zone settings, as well as the time settings are frequently determined by the perceived maximum load level on the lines in question, or on the power system in general. As mentioned before, the open access feature causes unexpected and unusual flow patterns to be imposed upon the network. Thus, the settings of these relays, which are affected by the system loading levels, are also suspect if the load levels can be expected to vary by significant amounts.

All of these protection function settings must be carefully examined in light of the anticipated flow patterns resulting from the open access transactions in order to maintain the quality of the protection functions provided.

5.7 Summary

It is clear that many problems associated with open access transmission are related to the redistribution of power flow on the network due to arbitrary points of power injection and withdrawal. Since transmission access involves transporting power from one location to another, it will necessarily complicate the control of power interchange among interconnected

utilities. It should be recognized that the power distributes according to the laws of electrical circuits, and consequently the problems created are not necessarily restricted to the systems which are geographically in a direct path between the source and load. The effects on losses, margins of security, and susceptibility to protection and stability problems may affect a much greater portion of the interconnected system, and must be evaluated with great care. The issue of open access transmission will affect system operating reliability and security in the following major areas:

- The increased number of entities supplying energy to and drawing from the transmission system will make AGC for controlling the bulk power system more difficult and complicated. The difficulty is partially due to reluctance to share information in order not to lose a competitive advantage.
- The redistribution of power flows could aggravate existing overload and low voltage problems to a much greater extent.
- Unless power supplies who request open access follow compatible protection designs, protection coordination which is essential to maintain system security cannot be ensured.

6. Non-utility Generators (NUGs) and Independent Power Producers (IPPs)

6.1 Introduction

Central generation made economical sense throughout most of the growth of the utility industry from the early 1900's through most of the 1970's. Economies of scale and improvements in technologies resulted in decreasing marginal cost of energy. However, in the 1970's both efficiency and cost of plant became constant or even less attractive with increasing plant size. Independently, the case for large central generation was further hammered by increasing environmental concerns and, almost independently, by a perceived need for national fuel independence brought on by the oil embargo.

These factors resulted in the Public Utilities Regulatory Policies Act (PURPA) in 1978. In an attempt to encourage the use of renewables and increase fossil fuel generation efficiency, PURPA qualified generators (qualifying facilities or QF's), using renewables and/or cogeneration, could sell energy to utilities at each utility's avoided cost. Ultimately, because of the unexpected drop in oil prices, many utilities were stuck with long term contracts that were uneconomical to the utilities and rate payers but encouraging to investors in the QF industry.

Recognizing that traditional utility economics and regulation needed revision, the National Energy Policy Act of 1992 (NEPA) redefined the utility function. This action was referred to as Public Utilities Holding Company Act (PUHCA) reform. As a result, electric wholesale generators (EWG's), not necessarily qualifying under PURPA, can demand access to a utility's transmission system for wheeling and a utility can initiate purchasing power from the EWG's under each state's guidelines. Consequently wholesale power markets will be served by more independent power producers. This new PUHCA could change the structure of the electric industry to a less vertically integrated and cost-effective identity. The consequence of favoring NUG's and IPP's is that regulatory commissions may not have the option of penalizing utilities for misjudging supply or demand.

So through PURPA and even more through NEPA, the door was opened to third party dispersed generation. Gone was the process, traditional for 40 years, of planning and siting large central generation and planning a corresponding transmission system to provide accepted levels of security and reliability. Non-utility generation may now constitute a small percentage of system capacity for most utilities. However, non-utility generation constitutes over 50 % of new capacity additions for some utilities. As the penetration of non-utility generation grows, utilities will realize that much of their generating capacities cannot be directly controllable by their energy control centers. Furthermore, the operating characteristics of those small non-utility generators are not desirable from the standpoint of maintaining system security. The present protection and control mechanisms will need to be re-engineered to allow small non-utility generation and/or storage to reach it's economic and technical potential.

Non-utility generation sources are by definition not under the control of the utility control center and personnel. Furthermore, the prime-mover sources may render them incapable of being controlled. For example, the solar or wind generators can only produce power when there is sufficient light, or when there is a strong enough wind. In general, it is the non-controllability of these generators that causes difficulty in power system operation and control. Other effects are the maintenance and protection of the interface between the non-utility generator and the power system. Also, personnel safety issues are also likely to surface, when non-utility generators are connected to a utility network. These and other issues are discussed in the following sections.

6.2 Controllability

The control of generation of a utility can be divided into several categories. From the viewpoint of relatively small generators, the main control functions of concern are the ability to turn the units on and off, and the ability to participate in the control of power system frequency.

6.2.1 System Frequency

Large central generators are driven by prime movers which may be steam or hydro turbines. Under steady-state operation of a generator, the net mechanical torque supplied by a prime mover is equal to the net electrical torque and there is no accelerating torque. It should be noted that mechanical torque generated by a prime mover cannot be changed instantaneously, but can only be changed with some time delay due to limitations of the mechanics of the machine. Strictly speaking, as a utility's system load varies continuously throughout a day, the utility's generators may always sense unbalance between the mechanical power input and the electrical power output. The unbalance results in either an accelerating or decelerating power which will cause the rotors of the generators to deviate from nominal speed. As a result, changes in system frequency occurs continuously.

System frequency should continuously be maintained close to the nominal value of 60 Hz to prevent damaging rotating equipment by operating it at off-nominal frequencies. Large steam turbines are especially vulnerable to off-speed operation and the units will be tripped as soon as abnormal frequencies are sensed by over-/under-frequency relays. It should be remembered that operation of the power system at off-nominal frequency for extended periods results in a time error on electrically driven time-keeping systems. The problem of clock times being in error is also corrected by the electric utility control system, by making a further adjustment to the frequency setting of its generators for specified time periods. One of the effects of the poorer quality of frequency regulation is that the frequency excursions around the nominal frequency become greater, and last for longer periods, although on the average they may be centered at the nominal frequency. Thus, although on an average the frequency is maintained, the time error, which is proportional to the integral of the frequency deviation, will tend to be greater. This may also entail a greater control effort on the part of the control systems of the utility generators.

Electric utility loads are composed of various electrical devices each having differing operating characteristics. A predominant part of the loads are motor loads which are sensitive to a change in frequency. Any load change will result in a change in rotor speed, which in turn cause the frequency-sensitive load to vary. Although the load change somehow compensates the frequency deviation, system frequency may still drift outside the acceptable limits. Therefore, some mechanism is needed to restore frequency back to within the limits. This is achieved by a coordinated control of the generating units and the system, as described below.

6.2.2 Automatic Generation Control

The first aspect of controllability deals with the participation of the non-utility generation in the control of frequency of the power system, as the load changes during the daily load variation. This mode of control is traditionally known as *Load Frequency Control* (LFC), or in more modern terms, *Automatic Generation Control* (AGC). The main thrust of this type of control can be explained by the simple illustration of Figure 6.1. Consider the operation of an isolated power system at a load P , which is being supplied by the system generation, at the normal power system frequency f_0 . As the load increases by an amount ΔP , the system frequency decreases by an amount Δf due to the natural regulation of the system generators. It is now necessary to increase the generation through a supplementary control, which raises the operating frequency back to f_0 .

Figure 6.1 Load frequency control

This is done automatically by the automatic LFC control on the turbine-generators of the electric utility. A change in speed of a prime mover can be made by a governor which senses the machine speed and sends control signals to the input valve to change the mechanical power output. Within a utility power system, many generators are electrically connected through a transmission network. To avoid each generator pulling the system frequency to its speed setting, a speed-droop feedback loop is provided to each unit's governor system. Through this means, the change in unit's power output can be determined for a specified change in frequency, and the system load can be shared by several units without interference among units.

Utilities are normally involved in selling or purchasing power on a short-term and/or long-term basis. To record all transactions, utilities monitor all their tie line flows. The difference between the total power leaving the system and that entering the system is checked against the scheduled value of interchange. Attempts should be made to make this difference equal to zero to fulfill interchange obligations. These require that the LFC be modified by the tie-line-bias controls, so that the system which contributes the load increment ΔP alone participates in the increased generation. Besides achieving economic dispatch of generators for the least production cost, the AGC system provides this capability of holding system frequency at a nominal 60 Hertz while maintaining the interchange power at the scheduled value.

An uncontrolled generation source will in effect behave like a random load, thus increasing the burden of control actions required of the utility system generators. On the other hand, the uncontrollable nature of the non-utility generation implies that amount of control effort expended by the utility generators is proportionately greater, as it tries to maintain the frequency of the system with an increased capacity due to the presence of the non-utility generation. Clearly, small amounts of non-utility generation will not affect the control aspects in a significant manner. Nevertheless, if the contribution of the non-utility generators to system load is significant, this may become a point of concern. In extreme cases, where the proportion of the uncontrollable generation is significant, the controllable generation will become proportionately smaller, and consequently the quality of frequency control of the power system will be degraded.

The controllability problems may be dealt with by making the non-utility generators participate in the load-frequency control function. This will require coordination with the utility control centers, and implementation of a local load-frequency control logic which mimics the behavior of the utility generators. The generation raise and lower commands are communicated to the utility generators from the control center over dedicated communication lines, and similar facilities must be installed at the non-utility generation sites, if their size becomes significant. This is not an insurmountable problem, however, it does call for added expenditures.

Of course, if the non-utility generation is uncontrolled (for example wind or solar sources without storage facilities), the control functions as described above for the load-frequency

control are not of much use. In such cases, one must accept the fact that the power system must contend with a greater fluctuation in its net load, and hence a somewhat poorer frequency regulation.

6.2.3 Generation Reserve Margin

Although utilities will depend more and more on NUG's and IPP's for meeting their generation capacity needs, most of the time those units can be neither directly controllable by utilities, nor be put on economic dispatch schedules. This non-dispatchability problem ultimately affects the disposition of generation reserve margin. In order to operate reliably, the power system must carry a certain amount of reserve generation, some of it in the form of spinning reserve. This reserve is needed to meet the load, should some of the utility generators be lost due to contingency conditions. NUGs and IPPs often run as base-load units. Therefore, during off-peak periods, generation from some of the utility's base-load units may have to back down to meet the generation-load balance. Therefore, it becomes increasingly difficult for utilities to maintain adequate operating reserve while attaining economic dispatch. In this case, a sudden loss of generation could result in a loss of load.

Even if an electric wholesale generator (EWG) uses conventional generation, such as combined cycles and turbines, it is not required to operate under a utility's automatic generation control (AGC). As far as EWGs are concerned, there is no advantage for them to do so because operating in a load following mode usually decreases efficiency and thereby reduces EWG profit. So, without special negotiated arrangements, utilities could be forced to back down their own base load units even if they are less costly. If the non-utility generation is a significant portion of the utility generation, and yet it is not assuredly on line when needed, then the needs of the reserves must be met from other utility owned generation, or with interchange contracts with the neighbors. In any case, the costs associated with providing the spinning reserve are left untouched by the presence of the non-utility generation. To this extent, the non-utility generation is unable to displace the utility owned generation.

6.2.4 Stability

Another aspect of the controllability is the controlling actions available to the utility-type generation for the control of transient instability of the power system. Electric power networks are subject to faults and other disturbances. Following the faults and their clearing by circuit breakers, the synchronous generators of the utility system undergo a transient oscillation. The oscillation could be stable, in which case the system returns to a new normal state. Upon occasion, the oscillation may be unstable, which may lead to system break-up due to loss of synchronization between groups of generators. In order to avoid such break-ups, in the first place, the utility relies upon the natural controlling action of its generators, whereby deviations from normal conditions produce machine torques which try to return to normal conditions. If a significant portion of the system generation does not have such a restorative effect, the task of controlling the transient stability swings will fall on generators

that have such a capability. Consequently, the strain on the power system would be greater, which will ultimately result in the power system being subject to instability in a larger proportion of cases. This is not acceptable practice, and will probably require that the utility step back from the prevailing load transfer capability, and thus restore its margins of stability to their previous values. This is, of course, at a severe cost penalty to the utility.

Instability of generators is also aided by special controls installed on the generators, such as excitation systems with supplementary controls, fast valving systems on steam turbine, etc. Such stability aids must be available to a modern power system, in order to have it maintain its operating economy at competitive levels. When the penetration of the non-utility generation becomes significant, controls of this type must be considered for the non-utility generators as well.

6.3 Reactive Power Support

The installation of any generation must be accompanied by the addition of reactive power sources. The delivery of real power in an ac network demands that it be accompanied by reactive power in order to maintain reasonable voltage levels in the network. Some types of generators are incapable of supplying reactive power; indeed, they demand reactive power supply from the utility grid. For example, solar generators are usually connected to the network through dc-ac converters of the Graetz Bridge type. These converters require reactive power of between 20% and 50% of their active power output. To accept power from sources of this type, the reactive power capability of the utility network may have to be increased.

In addition, NUG and IPP units are often designed to fit the business purpose of selling electric power, but are equipped to provide only a limited reactive power control capability. Therefore, if the total generation capacity from NUGs and IPPs does constitute a large portion of a utility's total installed generation capacity, it limits the utility's reactive power support capability, undermining the utility's ability to maintain adequate system voltages. Unless the utility provides other alternative sources of reactive power, the system could be prone to voltage collapse even under mild transmission contingency conditions.

All of the added reactive power requirement can not be met by shunt capacitors alone. When shunt capacitors are used, one must further consider the effect of these capacitors on the flow of harmonic currents in the network, as well as upon the possibility of creating self-excited modes of operation in induction generators as explained in the next section.

6.4 Self-excitation of Non-utility Generation

Certain types of non-utility generators, in particular induction type generators, are known to be capable of self excitation even when the utility connection is broken. Consider the system shown in Figure 6.2. When the utility connection is broken due to faults in the transformer, or for maintenance purposes, the non-utility generator remains connected to the load through the feeders as shown. If the feeders in question contain a significant length of a cable, or if

shunt capacitors are used for voltage correction, the induction generators may be self excited by the capacitance on the network. Under these conditions, the output frequency of the generators will settle at a value unrelated to the power system frequency. Furthermore, the output voltage magnitude, as well as the voltage waveforms will no longer resemble the normal power system quantities. Recall that a number of loads remain connected to the subsystem which is now being fed by the non-utility generator. Thus, these loads would now be subjected to the abnormal voltage magnitudes, waveshapes, and frequency.

Figure 6.2 A load remains to be connected to the non-utility generator after being disconnected from the utility system.

A number of loads are susceptible to voltage deviations from normal. For example, electronic equipment such as computers use dc converters, which are highly susceptible to voltage magnitude variations. Motor loads are affected by the power system frequency and voltage waveshapes. All equipment containing ferromagnetic cores would have increased power losses due to abnormal voltage waveforms. All of these issues must be considered, and appropriate measures implemented to avoid the occurrence of self-excited operation of this type of generators.

6.5 Planning Uncertainty

The maintenance schedule for NUGs and IPPs will most likely be determined independently by their owners, and may not necessarily be coordinated with that of the utility's plants. In other words, NUGs and IPPs may be unavailable when the utility needs them the most.

Furthermore, unforeseen unavailability of NUGs and IPPs would incur difficulties in the utility's operations planning such as determining unit commitment schedules. In short, unless the large number of small non-utility generators installed on a utility system are observable to the utility's control center personnel, they are expected to cause virtually all system security problems due to their lack of controllability and dispatchability.

Construction and installation of transmission facilities generally require a considerably long lead time for planning, conducting engineering studies, obtaining permits, and constructing the facility. The same can be said of building a utility's power plants. Consequently, the planning horizon of traditional transmission planning used to mesh well with the planning of the anticipated utility's central generation facility additions. However, NUG and IPP units are expected to be constructed within a much shorter time frame. Consequently utilities may not be adequately informed of any generation unit additions sufficiently in advance so that their transmission systems may be strengthened to accommodate the new generation sources. The severity of problems that may result from inadequate transmission systems is dependent on many factors including the strength of the existing transmission systems, sizes and locations of NUG or IPP units, etc.

Furthermore, it is conceivable that many small NUG and IPP units would be dispersed throughout the utility system. This possibility could result in balancing generation with load, which would promote secure transmission system operations. In general, the nature of transmission facility additions is lumpy. The implication in this characterization is that there is no easy way to increase transmission capacity uniformly throughout a wide geographical area. Therefore, unless there is urgency of a need for transmission capacity additions, utilities would likely to avoid adding any new facilities. This trend will eventually lead to heavy loading of all transmission facilities, which would be detrimental to system reliability and security.

6.6 Safety Hazard

Non-utility generators present some unique problems from the point of view of operations personnel safety, and safety of utility customer loads. Consider the non-utility generator connected to the utility system as shown in Figure 6.3. A temporary fault on the feeder A-B will be cleared by the protection system installed by the utility at station B. The protection system at the non-utility generation must also take similar action, and isolate the faulted segment from the source of power. The correct operation of this protection system is of course predicated upon the premises that the protection system design philosophy being used by the non-utility generation system is compatible with that provided by the utility at station B. If this is not the case, the segment AB may remain energized by the non-utility generator, or if designed to do so, may be reenergized after a pre-set time delay in the protection system at A. In such a case, the utility service crew, out for inspection of the faulty segment and possible repair, may be under the misapprehension that the segment is unenergized, and is thus safe for servicing. If this is not the case, it will cause a very serious safety hazard for the utility service crew.

Figure 6.3 A non-utility generator connected to the utility system

A similar concern exists regarding the hazard created by a downed conductor on a feeder, which may be tripped from the utility side. If the non-utility generation system does not come equipped with a suitable downed conductor detector, the conductor may remain energized from the non-utility generator, and create a serious threat to the life of people in the neighborhood.

6.7 Summary

NUGs and IPPs represent an increasing portion of utility's generation capacity additions. Unless the majority of NUGs and IPPs are under the control of the utility control center, the non-controllability of those generators will degrade the reliability and security of the utility system. The major areas of system reliability and security concerns due to NUGs and IPP are as follows:

- If the penetration level of NUGs and IPPs is high and the majority of those generators are outside of a utility's load frequency control, the utility's central generators may not have sufficient capability to adequately control the system.
- NUGs and IPPs may not be able to provide sufficient reactive power control capability that is needed to maintain adequate system voltages.
- Self-excitation of certain NUGs will present islanding and safety problems unless the generators can be tightly controlled by utilities.

7. Integration of Dispersed Storage and Generation into Utility Distribution Systems

7.1 Introduction

Economies of scale have traditionally dictated that large central generation be constructed and has resulted in the present structure of utilities. Utilities have built large and sophisticated transmission and distribution systems to transport the centrally generated power to the customer's premises. The resource planning divisions of most integrated utilities are distinctly segregated into generation, transmission and distribution. The distribution system has always been at the tail end of the planning process with much management attention having been given to generation resource planning. This is in spite of the fact that most of the interruptions that customers experience are due to faults on the distribution system. The distribution system has a very important impact on the perception of customers regarding the quality of service they are receiving. Recently, with industry facing stiffer global competition, lot of importance has been placed on the distribution system's ability to provide reliable cost-effective service.

The importance to industry of reliable, low cost service is one of the factors motivating the introduction of dispersed storage and generation (DSG) devices on the distribution system. Following the passage of PURPA there has been an increasing penetration of small dispersed storage and generation sources on the distribution system. The motivation for the growth of dispersed storage and generation is twofold. Firstly, the cost of the DSG units have been decreasing and the efficiencies of the units have been increasing which increases the favorability of DSG options. Secondly, regulatory policies have permitted non-utility owned power producers to connect to the utility grid. However, the introduction of DSG on the distribution system tends to blur the traditionally clear-cut demarcation of generation, transmission and distribution. It calls for an integrated approach to planning in utilities. While DSG offers many benefits, it also raises questions related to the problems that could be encountered as a result of the presence of these units. The primary concerns with the introduction of DSG are regarding the security and reliability of the power system. As the penetration level of DSG units increases, these issues will be of very significant importance.

7.2 DSG Devices

DSG devices are found in many varieties. The prominent ones include generator sets, photovoltaic arrays, fuel cells, storage batteries, solar thermal and wind generators. Generator sets use a diesel or natural gas powered engine and an electric generator to produce power. Photovoltaic (PV) systems use solar cell panels to convert solar energy into DC electric power which then may be connected into AC electric systems. PV technology can be used for stand-alone and grid-connected applications. Fuel cells generate electricity through an electrochemical reaction combining a fuel and oxygen to produce DC electric power. Battery technology uses an electrochemical process to generate electricity. Fuel cell and battery DC power may also be converted into AC power. Solar thermal technologies generate electricity

by concentrating sunlight using reflective surfaces to heat a fluid that powers a thermal engine. Wind generators produce electricity by harnessing the kinetic energy of moving air masses to rotate a turbine to which is connected a generator.

Because of the wide variations of the nature of DSG devices, their operating characteristics also vary widely. The size of a DSG unit could vary from a few kW to a few MW. The output of devices such as fuel cells is DC which requires interface circuitry to enable connection to the utility grid. Some types of devices may not be dispatchable and their generation may have no load following capability at all. The output of units such as wind generators are intermittent depending upon the weather conditions. The DSG devices could be connected either at the substation or on the feeder. With the characteristics of DSG devices being varied, the impact on reliability and security will vary according to the type of device considered.

However, it is possible to identify, in general, some of the important impacts of DSG units on system reliability and security. System security and reliability aspects are of critical importance in the operation and control of the power system. Distribution systems have to be controlled and operated to ensure reliable uninterrupted supply of power to customers. In addition, it is important to satisfy voltage requirements, line and equipment loading limits and constraints imposed by frequency, stability and harmonics. What impact the presence of DSG devices on the distribution system will have on the above-listed aspects of reliability and security will also vary depending on the penetration level of the devices. At low penetration some of the impacts such as injection of harmonics into the system may be negligible. At higher penetration most impacts become significant. At present most utilities have experienced only a low penetration of DSG devices. However the penetration levels are likely to increase in the future.

7.3 Voltage

One of the important impacts of introducing DSG units on the distribution system is associated with voltage. If there is a high penetration of non-utility owned dispersed generation sources, it is possible that there may be periods when the total generation exceeds the local demand. This may result in power injection into the utility system and voltages at certain nodes may exceed the maximum allowed limit. Since utilities are not likely to have control over when and how much energy the customer-owned generators are going to produce, the frequency and severity of the problem will also be beyond control for utilities. In particular, if the penetration level of non-utility owned generators is very high, the amount of the total generation from DSG devices could exceed the load served from a substation. This could result in a dangerous rise in voltage at some nodes with a possible consequence of utility and customer equipment damage. The severity of the voltage problem would depend upon the amount of dispersed generation and also on where the units are connected on the distribution system.

7.4 Protection

Protection in distribution systems has been designed based on the assumption that current flows only in one direction in a radial feeder operation. Fault current calculations, relay settings, fusing and protective device coordination have been traditionally designed based on this assumption. With dispersed generation this basic assumption is challenged. There could be multiple sources of fault currents which could pose a serious threat to system security and reliability. At high penetration levels of dispersed generating units, the multiple sources of fault current feeding into a fault could result in severe overloading of conductor sections and may also cause damage at customer premises. There would therefore be a need to re-design the protection schemes on the distribution system before a high penetration of DSG devices can be tolerated. Questions have been raised about the safety of crew performing repair work on sections of a feeder which might be energized by dispersed generators. Historically, the protection issue has been the primary reason for resistance to the introduction of dispersed generation.

It has been demonstrated that with small synchronous generators (less than 250 kVA) having large reactance characteristics, the fault current does not change significantly for different locations of the fault. This means that a small generator connected near the substation may be able to detect and respond to faults on an adjacent feeder or on the transmission system connected to the same substation. This could result in the generator being cut off from the feeder at certain times when it is unnecessary. With converters, faults occurring near the device can cause commutation failure or even damage to the converter. For faults occurring away from the device, there could be voltage unbalances leading to commutation failure.

The introduction of DSG devices also raises the issue of the impact of DSG on coordination among various protective devices. Because current flows only in one direction in a distribution feeder, if two protective devices in series are between the source and the fault, the trip times should be set such that the device that is closer to the fault trips to clear the fault. Typically there would be fuse-to-fuse, fuse-to-recloser, recloser-to-recloser, and recloser-to-breaker coordination on feeders. With DSG units connected, there are multiple sources and multiple directions of flow of fault currents. This will upset the coordination scheme on the feeder.

It is possible that a situation could exist where a substation transformer may overload during fault conditions if the penetration level of DSG devices is high. For example, suppose that a temporary fault occurs on a distribution feeder. In this case, the substation breaker will trip to clear the fault, and at the same time, all DSG devices on the feeder will also be disconnected from the feeder. After all the DSG devices are confirmed to be off line, the breaker may be reclosed to restore service to the feeder. If this event happens during a period when the substation transformer has been carrying load whose magnitude is close to its rated capacity, the loading on the transformer could exceed its capacity because a significant amount of the generation capacity contributed from the DSG devices will be lost. Therefore, until the DSG devices are re-connected to the feeder, service to the entire area which has

been served from the transformer could be jeopardized.

It is also possible that a DSG unit may continue to feed into a fault due to a failure to be isolated from the feeder. In particular, a large dispersed generator near the substation may feed into a fault on adjacent feeders. Therefore, it may be necessary to set the feeder protective equipment to trip very quickly so as to prevent any dispersed generator from feeding into the fault. However, this will result in difficulty in coordinating some of the devices on the feeder.

DSG devices can be particularly vulnerable to reclosing operation of protective devices. For instance, single-phase generators on an unfaulted phase may continue to operate while three-phase recloser opens to clear the fault and then recloses to test the downstream feeder section to see if the fault has been cleared by itself. Upon reclosing, if the out-of-phase voltages between the utility and the generators are large enough to cause high currents, the generators could be damaged.

In distribution system operation, loads are often transferred among feeders to restore service to unfaulted but out-of-service feeder sections. After a fault is located and isolated, appropriate sectionalizing and tie switches are closed and opened to restore service to certain unfaulted but out-of-service sections. Customers on the sections of the feeder that cannot be restored to service by load transfer will have to wait until repair work is completed. Load transfers can also be used to reduce feeder losses by reconfiguring the distribution system although this option is not commonly exercised due to present communication and control limitations. Load transfer is an important means of capacity utilization in distribution system planning. Loads are transferred among substations and feeders to balance loading on substation transformers and feeders.

If there are a number of DSG units present on the feeder, load transfers would have to account for the possibility that some DSG units may get transferred from one feeder to another along with the feeder sections that are transferred. This could result in overvoltage and/or undervoltage problems at certain points on the feeders affected by load transfers. Also the protection of the feeders could deteriorate as accumulated line impedances change. Unless protection schemes are adaptive in the sense that relays can recognize changes in the feeder configuration, faults on some feeder sections after load transfers may not be detected. In addition, the changes in the locations of DSG devices after feeder reconfiguration will make proper setting of relays much more difficult.

7.5 Harmonics

The impact of harmonics on the purity of signal supplied to the customer has traditionally been considered on a local basis. Large utility generators have been designed very carefully to minimize harmonic contents. Therefore, generators were rarely the source of harmonic problems. However, it is not economically feasible to design small dispersed generators in the same manner as large utility generators. Consequently, with a high penetration of

dispersed generators on the distribution system, the problem of harmonics becomes significant. For a grounded generator, third harmonics generated will flow in the neutral-to-ground circuit, and its magnitude will be three times the harmonic current in each phase. This current could trigger the ground fault over-current relays and cause a protective device to trip whenever the generator operates.

If the utility operates a grounded-wye system, the DSG may have to have a delta connection to short-circuit the harmonics. However, potential overvoltage problems could exist during faults on the utility system if the DSG device continues to feed the fault after the fault is cleared by a utility breaker. This is caused by reclosing operation, which incurs overvoltages on the ungrounded customer's side. On the other hand, the interconnection transformer may have a tertiary delta winding to localize the harmonic flow to the delta tertiary. The problem associated with this arrangement is that it will be difficult to coordinate the setting of the ground fault relay on the DSG side with that of the utility.

If the utility system is ungrounded, the interconnection transformer may be connected ungrounded wye-delta. To prevent the utility from feeding a grounded fault on the customer side, a grounding transformer can be installed to detect ground faults. For a delta-wye connection, open-delta connected potential transformer can be installed to operate ground fault relays.

7.6 Stability and Operability

Stability of a system is defined as the ability of a system to return to its original state following a disturbance. This state is called the *steady-state* of the system. If the system returns to exactly the same operating state as it was in before the disturbance occurred, the system is said to be *steady-state stable*. It is possible that the system may return, after a disturbance, to a state that is operationally different from the one it was in before the disturbance. If this state is an acceptable operating state then the system is said to be *transiently stable*. The nature of a disturbance on the system can be classified as small or large depending on the magnitude of the disturbance. *Operability* refers to the ability to provide and maneuver the output of a generating unit to satisfy system needs. Many small non-utility generation and storage technologies, particularly renewables, are *inertialess*, in that they have an electronic interface which excludes the mechanical inertia that traditional power system analysis has assumed. No adequate models exist to determine system response to a heavy mix of inertialess generators.

With DSG units on the system, there are two stability issues to be addressed - the new sources of disturbances on the system and the impact that they have on the stability of operations of the system. The issue of controlling the output of the units to satisfy changing load is also of importance. The utility should be able to perform unit commitment and economic dispatch of dispersed generating sources in much the same way as other generators in the system. However, the utility cannot do the same for those units which are owned by customers. Load following or the ability to change the generator output with changing load

is an important operability consideration. Some types of DSG units will not have the ability to follow load. With dispersed units operating as base loaded units, load following capability is not of concern as long as the penetration level is low. At high penetration levels, if the total amount of dispersed generation is significant compared to the total system generation, then the issue of daily load following will become significant.

7.7 Islanding

Dispersed generators could be line dependent or line independent generators. If a generator is line dependent, it will shutdown as soon as the utility supply is disconnected following the occurrence of a fault. Even with line-commutated inverters, if there is adequate capacitive compensation, self-excitation is possible. However, the voltage and frequency is not likely to be within desired limits and there could be damage to loads connected.

Line-independent generators can continue to operate even after the loss of utility supply. In an islanded mode of operation, if the total load in the island is greater than the capacity of the dispersed generator supplying that load, it could result in reduction in frequency and voltage at the generator. This could cause damage to the generator. With a synchronous generator, if the total load in the island is less than the generator capacity, then overspeeding of the generator and high voltages could cause structural damage.

Although the islanding mode of operation is considered to be undesirable by utilities for safety reasons, it can reduce the amount of load that would be lost after the feeder section is isolated from the utility system. Therefore, the islanding operation can be considered to improve the system reliability by reducing outage duration for those customers who otherwise have to wait until repair work is completed. In order for an area to be successfully served in an islanding mode, there has to be a good match between the available generator capacity and the load. Also the generators must be equipped with governor capability to maintain the frequency within the isolated area at an acceptable level.

7.8 Benefits of DSG

The introduction of dispersed storage and generation shows early promise of providing many benefits. Small dispersed generators can be used on the distribution system to satisfy growth in demand locally thereby deferring/avoiding expensive generation and transmission additions. Small dispersed generation provides the flexibility to make incremental modular additions to the system. In the planning process, if the load growth is forecast to cause an overload at a substation transformer or on some line sections, a number of alternatives are considered such as replacing a substation transformer, adding a new substation, reconductoring and transferring load. With DSG, it may be possible to install and operate small dispersed energy sources which can be brought on line at peak load conditions to supplement the supply from the substation source. In effect, supplying loads locally with DSG appears to the remainder of the system like a reduction in load. This assumes that the units are controlled and dispatched by the utility. This alternative might be cheaper than the conventional planning

alternatives that are typically considered. The reduction in the peak will also result in a reduction in losses. It is possible to provide voltage support using some of the dispersed generating sources. The dispersed generating sources that utilize renewable sources of energy such as solar and wind have fewer unfavorable environmental impacts. It is expected that increased penetration of dispersed generation and storage will help defer transmission construction during the next decade. However, in some cases transmission may need to be strengthened to insure stability of partially islanded areas of load where dispersed generation has penetrated beyond the point of controllability.

The reliability of a system is a measure of the performance of the system related to its function of ensuring an uninterrupted supply of power to all customers. Reliability of a system is usually measured in terms of a number of indices that reflect the frequency and duration of interruptions for various feeder locations and for the system. Predicting the reliability indices for the future can be done using a probabilistic analysis based on the historical failure rates of various components on the system. With DSG units present on the system, the failure rates of these units will also have to be accounted for in the computation of the indices. With most of the supply interruptions to customers being due to faults on the distribution system and with the possibility of long down times for some remote generating units, the impact of DSG on system reliability becomes significant. It is noted that currently there is little historical outage data available due to the low penetration of DSG units.

7.9 Summary

Integration of dispersed storage and generation into utility distribution systems could present numerous operation and control problems if the penetration level of DSG devices is high. Traditionally, distribution systems have been designed and operated on the premises that current flows only in one direction in a radial distribution feeder. With multiple DSG devices installed on a feeder acting as sources, the conventional control and protection schemes will have to be changed. This condition will lead to the following problems mostly occurring in distribution networks:

- Fault current calculations, relay settings, and protective device coordination will have to be re-examined to accommodate DSG devices.
- Depending on time and locations, DSG devices could create a dangerous rise in voltage. Some DSG devices will need reactive power support from the utility system to operate.
- Line-independent generators can continue to operate after the loss of utility supply. This condition will cause islanding and safety problems.

8. EMF and Right-of-Way Limitations

8.1 Introduction

Concern over electric fields became apparent in 1974 in New York during hearings on proposals to build two 765 kV transmission lines. The evidence cited was a 1960's Russian study reporting illness in switchyard workers exposed to high electric fields. A number of investigations were begun by Edison Electric Institute (EEI) and later by the Electric Power Research Institute (EPRI) to determine the cellular mechanism and health effects of high electric field exposure. None of these studies were conclusive. However, having looked at the evidence available, an independent science advisory panel in Minnesota concluded that there was no scientific basis to believe that power lines proved a hazard to human or other animals.

Electric fields cannot penetrate more than a few millimeters into biological tissue. However, magnetic fields do reach deep tissue and organs. So, in 1979, when two Denver area studies showed a weak correlation between childhood cancer and magnetic field exposure, the EMF issue began to attract broader scientific inquiry and corresponding public concern. Some investigators even began to develop physical models for the interaction of low frequency magnetic fields and cell physiology.

Recent research has moved towards epidemiological studies using statistical inference rather than on directly measurable or modeled biological effects. Two recent Swedish studies showed some correlation between transmission line magnetic field exposure and illness, but the results were admittedly inconclusive and contradictory, despite the attention given by the American media. A University of Southern California study, somewhat similar to the Denver studies, also showed some correlation, but again, the inference was slight and was considered by some to be a statistical aberration.

At present there is no way to satisfactorily demonstrate to the public that there is no danger posed by existing exposure to EMF, nor is there a biological model adequate to determine safe guidelines. As a result, the evidence submitted to regulatory agencies consists mainly of anecdotal and weak statistical evidence. The National Energy Policy Act of 1992 includes a five-year, \$65 million federal-nonfederal R&D program giving DOE overall responsibility for EMF research. However, as one DOE official recently put it "There's no end in sight to the controversy - we will never prove there is no ill effect."

There is precedence for public outcry stopping the operation of existing transmission lines. Houston Power and Light was forced to discontinue its use of a 345 kV line built across a school district's property. The court ruled that the utility had abused its discretion even though no one was determined to be placed at risk by the lines being built. The EMF issue parallels the nuclear power debate where ultimately the scientific community's failure to provide adequate and uniform assurance resulted in the popular belief that no level of emissions was safe. Over the next decade highly visible lines near populated areas will be

under increasing, if often inconsistent, protest.

As the EMF issue is more publicized, it becomes more difficult to site and build transmission substations and lines. To avoid long delay in getting necessary permits for acquiring new right-of-way (ROW), lines are often double-circuited to utilize the existing ROW. Consequently inclement weather or accidents can cause greater disruption on transmission systems since a pole or tower failure would often mean a double contingency. Also to avoid building new transmission lines, utilities are attempting to load the existing transmission systems to their full capacity. Flexible A C Transmission Systems (FACTS) are being studied and developed to achieve this goal. However, placing FACTS into practice will continuously reduce transmission system operating margin, and will ultimately lead to degradation of bulk power system reliability and security.

To better appreciate the impacts of not building transmission lines due to EMF concerns on power system reliability and security, characteristics of a transmission line is discussed below as to its ability to deliver electric power. In general, the capability of a transmission line to deliver power depends on a number of factors and parameters. Some of the factors are related to system configurations, operating states, and load characteristics while others are associated with the transmission circuit itself. Some of the important factors affecting the transmission line limitations are described below.

8.2 Transmission Line Rating

Four parameters - resistance, inductance, capacitance, and conductance - affect the ability of a transmission line to perform its function. For HV and EHV systems, inductance and capacitance are the two most important parameters in evaluating the performance of a line. Inductance is determined by the geometric mean radius (GMR) of conductor, spacing between phase conductors, phase rotation, line configuration such as bundling and paralleling. Capacitance of a transmission line is the result of the potential difference between conductors. The series reactance of a transmission line is determined by inductance; capacitance affects the line performance via line charging.

One of the factors affecting a transmission line's ability to transmit power is the conductor thermal capability. It depends on both characteristics of the conductor itself and weather conditions such as wind speed and direction, solar radiation and ambient temperature. The minimum distance that should be maintained between power conductor and earth or buildings is specified in safety codes. The vertical distance between line conductors is determined by the pole or tower height and the conductor sag. A certain amount of sag is allowed in transmission line construction and operation. Increasing line loading increases sag thereby decreasing vertical clearances. If loading becomes too great, hazardous conditions could result. The thermal rating of a transmission line is usually determined by the span which results in the worst conditions as to weather condition and clearance. Consequently the thermal capability of a line determined this way is a conservative estimate.

Sag can be estimated by measuring conductor temperature directly. If temperature sensors are installed on a line which limits power transfer capability, the line may be loaded above the static line rating. Sometimes it is quite difficult to pinpoint the worst spot of a line. In this case, a possible loss of life should be carefully evaluated before a *dynamic conductor rating* is considered for the line. Judicious implementation of dynamic thermal rating will allow considerable increase in loading of thermally limited lines without doing physically something on lines such as resagging, restring, and reconductoring.

8.3 Stability Limit

Transmission lines are rarely loaded up to its thermal ratings. The amount of real power transmitted over a transmission line is approximately a function of the reactance of the line, the sending-end and receiving-end voltage magnitudes and the phase angle difference. Mathematically it can be written as

$$P = \frac{V_s \times V_r}{X} \sin \delta$$

where V_s and V_r are the sending-end and receiving-end voltages, respectively, X is the transfer reactance of the line, and δ is the power angle between V_s and V_r .

It is noted that the phase angle increases as the real power transmitted increases. The line can deliver the maximum power when $\delta = 90^\circ$. The maximum value of $V_s V_r / X$ is the steady-state stability limit of the line. In general, this stability limit is much lower than the thermal rating of a transmission line.

Power transmitted can be increased by increasing the sending-end and/or receiving end voltages, as can be seen in the above formula. However, it can also be increased by reducing the reactance of the line, X . Reduction in X can be achieved by constructing additional transmission lines. Construction of a transmission line can not only reduce the reactance between the two end points of the line but also reduce system reactance in general. If transmission lines can not be built due to EMF concerns or right-of-way restrictions, this stability limit will reduced considerably under certain critical contingency conditions.

The EMF and right-of-way limitation will shift line flows, and possibly cause heavy loading on certain critical lines. Faults on those lines are more likely to cause instability since they tend to yield greater acceleration during the faults and result in a weaker transmission system upon clearing the faults. These possibilities will lead to degradation in transient stability margin as long as badly needed transmission lines cannot be constructed because of EMF and right-of-way concerns.

8.4 Generation Redispatch

The level of magnetic field intensity associated with a transmission line depends on the amount of current flowing in the line. Therefore, EMF concerns can be mitigated by loading those transmission lines in problem areas below a certain threshold value. This requires control of power flow through the transmission system. The most effective way to reroute the flow of power can be done by generation redispatch. Unless the system has been designed to accommodate such generation redispatch, several undesirable operational problems may result from it.

First, generation redispatch would cause redistribution of power flow through the transmission system, which in turn may cause overloading of other already heavily-loaded transmission lines. This may also create low voltage conditions in certain areas, which would not occur otherwise. Secondly, the utility's ability to maintain adequate spinning reserve may be severely restricted. This happens if the result of generation redispatch unload base-load units while those units normally reserved for spinning reserve are heavily loaded. Thirdly, the utility's inability to construct necessary transmission lines will weaken its transmission network. This could lead to a situation where the utility may not be able to implement generation redispatch that will be necessary to alleviate overload, low voltage, or stability problems.

8.5 Summary

EMF concerns and right-of-way limitations have been two major factors that forced utilities to delay or cancel many transmission line projects in the U.S. This will undoubtedly weaken transmission systems, causing degradation in system reliability and security. In that regard, the impacts of these issues on system security can be summarized as follows:

- Since utilities have no options other than loading the already heavily loaded transmission systems at their full capacity, steady-state and transient stability problems could arise even under mild contingency conditions.
- Again, due to heavy loading, overload and low voltage problems are likely to occur, leading to possible voltage collapse.

9. Clean Air Act Amendments

9.1 Introduction

The Clean Air Act Amendments of 1990 has the goal of reducing annual sulfur dioxide emissions by 10 million tons and annual nitrogen oxide emissions by 2 million tons from 1980 levels for all man made sources. Of course, fossil electric generating units, both utility owned and non-utility owned, will be primary targets of this legislation. The law provides a limited source of emission allowances for all generating units. The process differs between utility and non-utility generators and the available literature does not yet agree as to whether both ownerships have equal access. Allowances can be purchased, traded or pooled within specified regions.

Continuous emissions monitoring systems (CEMS) will be required by 1995 to insure that plants within a control region are operating within their allowances. An example has been given where 7 plants reduced SO₂ and NO_x emissions by 40 % by phone calls to the operators from someone monitoring the CEMS. In many cases this will lead to cleaner plants being operated at greater capacity while plants producing higher emissions per kW will be backed down. Meanwhile utilities will use tradable emission permits to meet the regulated level of emissions.

To meet the emissions standards, utilities will exercise all options available to them to minimize expenditure. Options include using emission permits, low-sulfur coal, scrubbers, and power purchases. The price of permits will be dependent on the cost of using alternative methods to meet the same emission level that the permits would achieve. Therefore, demand for allowances would be dependent on costs of other options for meeting emission standards and on projected load growth. In that sense, the price of allowances could be volatile. It is important that emission credits and expenditures required to meet the air quality guide will have to be treated fairly by regulators so that utilities can use it as a guide to minimize the total operating cost.

9.2 Generation Redispatch

The Clean Air Act Amendments will force utilities to change their strategies to meet customer demand in order to meet the air quality standards. This gives rise to several operating problems that will directly affect system reliability and security, as discussed below.

9.2.1 Economic Dispatch

For a regulated industry such as the electric utility industry, minimizing costs is the goal of everyday business. Costs can be reduced by eliminating capital expenditure for those facility additions that are deemed to be unnecessary. This can be accomplished by careful planning and improvement in design of apparatus and systems. Savings can also be achieved by minimizing operating and maintenance costs through efficient operations and fuel

management. Fuel costs account for much of a utility's operating costs. Therefore, utilities having several power plants have a need for economically operating their plants to meet ever-changing system demand. The strategy for economic distribution of load among several generating units is called the *economic dispatch*.

Modern power systems consist of a mixture of various power plants such as coal-fired steam plants, nuclear plants, oil or natural gas internal combustion units, hydro electric plants, pumped hydro storage plants, etc. Each of these various plants has different operating characteristics and is utilized with different objectives to meet the overall system demand. For instance, large coal-fired steam units or nuclear units are mostly base loaded in that output power level remains constant regardless of the load level. On the other hand, internal combustion generating units are used as peaking units which are on line only during peak load conditions.

Sophisticated computer-based dispatch control is employed at most power companies in the U.S. At a fossil-fuel plant, power output of a unit in megawatts depends on fuel input in Btu. Therefore, the operating costs of the unit, for which fuel cost is the principal item, can be expressed in terms of the power output. If fuel price is specified, the fuel requirement for a specified output can be easily determined in dollars.

The criterion for economically serving the load by many generating units is whether the total fuel cost increases or decreases as the outputs from individual units are increased or decreased. In this regard, the concept of incremental cost is used in economic dispatch. Incremental fuel cost for a unit is actually determined by the increased cost of fuel that is required to increase the power output by a small amount for some period of time.

The guiding principle for economic dispatch may be explained as follows. Suppose that generation from the unit with higher incremental cost is decreased while the unit with lower incremental cost increases its generation by the same amount. The net result in this generation adjustment is a reduction in total generation cost to meet the demand. This adjustment of generation can be continued until the incremental fuel costs of the two units are equal. The same reasoning can be extended to cases involving more than two units. Modern economic dispatch procedures also account for losses in the transmission lines. But the underlying principle remains the same in determining economic dispatch.

9.2.2 Constrained Dispatch

Inadequate Ramp Rates

To meet the emissions standards, utilities may no longer be able to pursue economic dispatch of generating units. For instance, generation from those units burning high sulfur coal, which may be ranked high in the economic dispatch list, may have to be drastically reduced to meet emission limitations. In other words, plants will instead be dispatched to meet the requirements of emission credit banking and inter-utility pooling to trade credits. This may

result in such a loading pattern that causes the ramp rates of those units on spinning reserve to be slow. Such spinning reserve would not be responsive to rapid load increases.

Redistribution of Line Flows

Often transmission systems are planned and designed to best support dispatch of both the existing and future units in the most economical way. Inter-utility interconnections are also planned to support such dispatch patterns. Constrained dispatch to meet the emissions standards will considerably alter such patterns of power flow distribution and thus system voltage profile. In some cases, the shift in generation may result in little reactive power support in certain areas, causing possible voltage instability. The resulting complexity will force utilities to operate transmission systems outside of scenarios considered by transmission planners. In other cases, in an attempt to meet the emissions standards, operators may have no choice but to operate the transmission system up to its critical limits so that any ensuing casual contingency could trigger detrimental cascading transmission failure events.

It is clear that improved real time control, communication and data availability will be necessary for the utility industry to operate under the new regulations. This need arises because the industry does not yet have the experience to develop predictable emissions dispatch plans. Nor do we have enough plant operating data to form such plans.

Power Import

Utility's base-load units that burn high sulfur coal may have to be either shut down or severely underutilized to meet the emission standards. To fill the shortage of power generation, a significant amount of power may have to be imported from neighboring utilities. This may result in loading already heavily loaded tie lines beyond the safe limits even during normal operating conditions. Details concerning the operational consequences of heavy power transfer between utilities have been discussed earlier in Section 5 dealing with the transmission access issue. Therefore, they are not repeated here again.

9.3 Real-time Pricing

Some advocate the use of real-time pricing as a means to control electricity demand. A sophisticated communication system will enable utilities to read residential customers' meters remotely and in real time. By sufficiently varying prices customers may be encouraged to change their electricity use patterns so as to shift some of their demand from peak periods to off-peak periods. This could result in less power generation from inefficient higher polluting power plants. It has been claimed that spot pricing could therefore not only save money for both utilities and customers, but also indirectly affect the effort to reduce air pollution caused by high sulfur coal-fired power plants. However, unless real time pricing is implemented judiciously, unanticipated problems could be created. For instance, a new peak could be created by consumers who change their electricity use pattern in response to price change. Also if a large number of consumers' response occurs within a short period of

time, the inadequate ramping capability of a utility's generation system may not be able to match the sudden load change. This could result in a large frequency excursion.

9.4 Summary

The Clean Air Act Amendments will force utilities to change their strategies for meeting customer demand while satisfying air quality standards. This gives rise to numerous operating problems both in the generation and transmission systems, as summarized below.

- Generation from those units burning high sulfur coal may have to be reduced substantially to meet emission standards. The resulting dispatch of generation units may not be able to provide flexible control capability such as adequate spinning reserve with sufficient load following capability.
- As a result of constrained dispatch, power flows on transmission lines and transformers may cause overload or low voltage problems, which will ultimately threaten system reliability and security.

10. Summary and Conclusions

The electric utility industry in the US is experiencing much internal and external structural reform due to economic and regulatory pressures. A series of regulatory acts ranging from the Public Utilities Regulatory Policies Act in 1978 to the National Energy Policy Act of 1992 continued to redefine the utility's missions and goals. At the same time, environmental concerns such as EMF concerns and clean air requirements have restricted the construction of additional generation and transmission systems that are needed to meet the nation's increasing electricity demand. All these issues are expected to influence the US electric utilities' ability to operate the power system securely .

Among many issues that will influence reliability and security of power system operations, five most critical issues have been identified and analyzed in Sections 5 through 9. They are

- transmission access/retail wheeling
- non-utility generators and independent power producers
- integration of dispersed storage and generation into utility systems
- EMF and right-of-way limitations
- Clean Air Act Amendments.

Analysis revealed that all five issues would directly and/or indirectly affect virtually all aspects of transmission and energy management system operations. The severity of impacts will, of course, depend on system characteristics of specific utilities, their operating practices, and circumstantiality. The system conditions that may endanger system reliability and security from the operations viewpoint could be many. Some of the conditions may lead to another set of conditions which may eventually result in systemwide security problems. For the purpose of summarizing the results, the five issues are tabulated in Table 10.1 according to their impacts on various system problems which could lead to detrimental system insecurity.

In the table, the degree to which each power system problem is affected by individual issues is represented by high (H), medium (M), and low (L). As noted above, the impacts of the issues on system problems cannot be easily generalized, and therefore, the determination of this severity must be made based on engineering judgment. In fact, in a given locality, it may be possible to establish a strong relationship between a particular issue and a specified system problem based on local conditions. However, to maintain consistency in the analysis, the results in Table 10.1 have been obtained by examining whether the impact is direct/indirect, or primary/secondary, and likelihood of occurrence.

System Problems Affected	Issues				
	Transmission access/Retail wheeling	NUG and IPP	Dispersed storage and generation	EMF and ROW	Clean air act amendments
Spinning reserve	L	H	H	L	H
AGC	H	H	H	L	H
Load following capability	L	H	H	L	H
Transient stability	M	H	H	H	M
Facility overload	H	L	L	H	H
Voltage instability	H	M	M	H	L
Voltage control	H	M	H	H	M
Protection	H	H	H	L	L

Table 10.1 The degree of the impacts of the five issues on power system problems is represented by high (H), medium (M), and low (L).

Conclusions

As expected, open transmission access/retail wheeling and EMF/ROW limitations will mainly affect transmission system operating conditions such as facility overload, voltage stability, etc. NUGs and IPPs are expected to mostly impact generation system control problems such as spinning reserve, load following capability, etc. The Clean Air Act Amendments will directly affect coal-fired power plant operations, and hence, it will also mostly impact generation system-related problems. While the other four issues concern bulk power system operations, dispersed storage and generation devices are anticipated to be installed mainly on subtransmission and distribution systems and their locations would be widely dispersed throughout the system. In the table, dispersed storage and generation is shown to affect many power system problems to a high degree. This is due to the fact that dispersed storage and generation devices are likely to be geographically widely scattered, and thus they will affect a large number of system components. However, it should not be construed that the issue is more important than the other four issues.

There is no doubt that reliability and security of the US power systems will be significantly impacted by the five issues examined. Although the five issues have been analyzed individually, strictly speaking, they have overlapping impacts on power system operations. For example, since NUGs and IPPs should be connected to transmission systems to get their generated power to utility customers, the transmission access issue must be addressed simultaneously. The complexity of the actual operating problems caused by the combined effects of several issues could be significantly greater than that from individual issues. Nevertheless, the identification of the combined impacts can be achieved by superimposing individual impacts.

This report examines the five critical issues that the U.S. electric utility industry will be facing over the next decade. The investigation of their impacts on utility system reliability and security is limited to the system operation viewpoint. Those five issues will undoubtedly influence various planning aspects of the bulk transmission system. However, those subjects are beyond the scope of this report. While the issues will also influence the restructure and business of the utility industry politically, sociologically, environmentally, and economically, all discussions included in the report are focused only on technical ramifications.

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**IDENTIFICATION, DEFINITION AND EVALUATION
OF
POTENTIAL IMPACTS FACING THE U.S. ELECTRIC
UTILITY INDUSTRY OVER THE NEXT DECADE**

Task 1: Identification and Definition

Research Work

for

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Attributes Affecting System Reliability and Security

The integrity of the electric power delivery system is determined by the manner in which the system is planned, how it is operated, and how it is controlled. Various issues of a technical, technological, physical, institutional, and financial nature could adversely affect the ability of the national power delivery system to continue to fulfill its role. The issues to be identified in this task will be examined for their likely impact on system reliability and security from the system operations viewpoint. It is noted that the reliability and security of power systems can be affected by various system design, configuration, and operating conditions. In particular, *system reliability* and *security* are considered to be adversely affected if the operating conditions and states of a power system reveal one or more of the following *attributes*:

- instability (from the rotor angle standpoint)
- voltage instability
- abnormal steady-state operating conditions (low voltage, line and equipment overload, and frequency excursion)

In order to determine whether each of the issues identified later in this document would critically affect system reliability and security, we now examine how various aspects of system design, configuration, and loading conditions may lead to system conditions possessing each of the three attributes.

Transient and Steady-state Instability

Power system stability may be defined as that property of the system which enables the synchronous machines of the system to respond to a disturbance from a normal operating condition so as to return to a condition where their operation is again normal. Stability studies are usually classified into two types depending upon the nature and order of magnitude of the disturbance. These are *transient* and *steady-state stability* studies.

The *steady-state operating condition* of a power system is an operating condition in which all of the operating quantities that characterize it can be considered to be constant for the purpose of analysis. A power system is *steady-state stable* for a particular steady-state operating condition if, following any small disturbance, it reaches a steady-state operating condition which is identical or close to the pre-disturbance operating condition.

Transient stability studies are aimed at determining if the system will remain in synchronism

following major disturbances such as transmission system faults, sudden load changes, loss of generating units, or line switching. A power system is *transiently stable* for a particular steady-state operating condition and for a particular disturbance if, following that major disturbance, it reaches an acceptable steady-state operating condition.

There are two factors which can act as guide criteria for the relative stability of a generating unit within a power system. These are the *angular swing* of the machine during and following fault conditions and the *critical clearing time*. It is apparent that the H constant related to inertia and the transient reactance of the generating unit have a direct effect on both of these criteria. It is noted that the smaller the H constant, the larger the angular swing during any time interval. On the other hand, the maximum power that can be delivered decreases as the transient reactance of the machine increases.

When a fault occurs on a system the voltages at all buses are reduced. At generator terminals the reduced voltages are sensed by the automatic voltage regulators which act within the excitation system to restore generator terminal voltages. The general effect of the excitation system is to reduce the initial rotor angle swing following the fault. This is accomplished by boosting the voltage applied to the field winding of the generator through action of the amplifiers in the forward path of the voltage regulators. Modern electrohydraulic turbine governing systems have the ability to close turbine valves to reduce unit acceleration during severe system faults near the unit. Since single-phase faults occur more often than three-phase faults, relaying schemes, allowing independent or selective circuit-breaker pole operation, can be used to clear the faulted phase while keeping the unfaulted phases intact, thereby extending the critical clearing time.

Although the above control schemes are excellent control mechanisms to increase overall system stability, they are not likely to be affected by the issues to be examined in this task. However, it is noted that reducing the reactance of the system during fault conditions also enhances the possibility of maintaining stability. This aspect of system design strategies aimed at lowering system reactance will be most affected by some of the issues that will be evaluated later.

Reducing the reactance of a transmission line is one way of raising the maximum power that can be delivered. Compensation for line reactance by series capacitors is often economical for increasing stability. Increasing the number of parallel lines between two points is a common means of reducing reactance. When parallel transmission lines are used instead of a single line, some power is transferred over the remaining line even during a three-phase fault on one of the lines unless the fault occurs at a paralleling bus. For other types of faults on one line, more

power is transferred during the fault if there are two lines in parallel than is transferred over a single faulted line. For more than two lines in parallel the power transferred during the fault is even greater. Power transferred is subtracted from power input to obtain accelerating power. Thus increased power transferred during a fault means lower accelerating power for the machine and increased chance of stability.

Voltage Instability

In some part of North America, power transfer capability has been usually limited by transient stability. Recently the voltage stability problem has begun to limit power transfers especially in western North America. As utilities are being forced to operate the system close to the thermal or steady-state stability limits, maintaining adequate system voltage has become a major concern for operators. *Voltage stability* is defined as the ability of a system to maintain voltage so that when load admittance is increased, load power will increase, and so that both power and voltage are controllable. *Voltage collapse* is the process by which voltage instability leads to loss of voltage in a significant part of the system. *Voltage security* is the ability of a system, not only to operate stably, but also to remain stable following any reasonably credible contingency or adverse system change.

Voltage instability is triggered by disturbance or change in system operating conditions requiring reactive power demand which is in excess of the system's capability. The inability of the system to provide the needed reactive power support is mainly due to intensive use of available generation and transmission systems. Considering that addition of any equipment is scrutinized today by most utilities to explore possible deferment, it is not surprising to begin to see the phenomenon of voltage instability.

The reduced capacity margin problem mentioned above is compounded by increased use of shunt capacitors for reactive compensation. Excessive use of shunt capacitors to increase transfer limits would result in a voltage collapse prone system. Since shunt capacitor reactive output decreases with the square of voltage, the capability of the capacitors to supply needed reactive power will be reduced as the critical voltage falls below the normal operating voltage range.

Voltage instability has been observed for different time frames ranging from seconds to tens of minutes. In general, it is classified into transient, classical, and long-term voltage stability according to three time frames.

For a short-time frame up to ten seconds transient voltage stability is meant. Voltage instability

is caused by unfavorable load such as induction motors and dc converters. Under low voltage conditions, the reactive power demand of induction motors will increase, contributing to voltage collapse. The action of load tap changers is not fast enough to cope with the transient voltage collapse phenomena associated with induction motor load. Dc links also render weak ac systems, causing voltage stability problems. During disturbances under stressed transmission loading conditions, western North America power systems have shown signs of voltage collapse tendencies.

Classical voltage stability is concerned with the time frame of one to five minutes. The terms "post-transient" or "mid-term" voltage stability have also been used. Load tap changers and distribution voltage regulators will react automatically to boost sagging customer voltage, but operator intervention is not possible during this time frame. A system may be transiently stable. However, under the condition of large power import from remote generation, loss of large generators in the load area or loss of major transmission lines could cause large reactive power losses along with voltage sags in the load area. As load tap changers and distribution voltage regulators try to restore customer voltage, voltages on the transmission system further decrease. As a result, the generation and transmission system can no longer provide needed reactive power support, and the system collapses.

There have been several incidents that voltage deterioration occurred over twenty to thirty minutes. These phenomena are referred to as long-term voltage instability. During continuous load buildup transmission lines and transformers may be overloaded, triggering breakers to trip the overloaded elements. In addition, load may lose diversity due to prolonged low voltage conditions. Under these circumstances following shorter time-frame voltage instability, long-term voltage instability may occur. During this time frame operator intervention such as load shedding would be possible to avert voltage collapse.

Abnormal Steady-state Operating Conditions

Power systems should be designed with sufficient capacity within each area to serve area loads under various conditions. Design of power systems should also take account of providing capability to transfer power from one area to another. Transient stability of the interconnected systems should be maintained during and after the most severe probable disturbance. That aspect was discussed earlier. Operating conditions should also be maintained within limits under steady-state conditions. Conditions indicating abnormal operation are *low voltage*, *line and equipment overload*, and *low frequency*. In the case of overload, normal and emergency limits may be applicable prior to and following disturbances, respectively.

Transmission systems do have limits. If the limits are exceeded, it can cause transmission lines to sag or even burn down. Low voltage conditions in a local area that may not develop into voltage instability can still cause excessive reactive power flow in lines and equipment, thereby causing overload. Techniques for improving steady-state voltage include series compensation, shunt compensation, excitation systems, static VA compensation, synchronous condensers, and transformer tap optimizations.

Each day, it is not unusual that some transmission lines are out of service for maintenance. It is also common for transmission lines to develop a short circuit and need to be disconnected. Transmission systems should be planned, designed, and loaded with scheduled as well as forced (unscheduled) outages in mind.

A sustained frequency excursion is a sign of major generation-load unbalance. It is important for the trouble area to establish generation-load balance as soon as possible in order to restore frequency. This will facilitate any separated areas to be reparalleled so that the integrity of the entire system can be maintained. Once the generation-deficient area is identified, load relief may be performed. In general, load relief is accomplished by reducing voltage or by load shedding or both.

Identification of Issues

Eleven (11) issues of an environmental, political, sociological, and economic nature have been identified. Based on the three attributes discussed above, the eleven issues were classified into two sets (critical and non-critical) according to the severity of impacts on system reliability and security, as shown below. A brief discussion of the rationale for inclusion or exclusion of each issue from the critical set is provided immediately following the list of issues.

Critical Issues

- Transmission access/retail wheeling
- Non-utility generators (NUG's) and independent power producers (IPP's)
- Integration of dispersed storage and generation into utility distribution systems
- EMF and right-of-way limitations
- Clean Air Act Amendments

Non-critical Issues

- Design certification on standard nuclear power plants
- High- and low-level nuclear-waste repository site
- Industry restructuring/PUHCA reform
- Long-term stability of natural gas price
- Time-of-use and place-of-use pricing
- Quality of power supply

Discussion

The eleven issues identified above are now briefly discussed.

Transmission Access/Retail Wheeling

Transmission access and the wheeling of power through transmission systems is nothing new to the utility industry. Most of the electricity generated in the lower 48 states and in Canada is transmitted over four integrated bulk power networks. There are 153 separate power control areas representing either individual utility service areas or those of power pools. However, wheeling and transfers through these networks has been planned for with adequate capacity and control to assure acceptable levels of security.

Wheeling and transmission access becomes a concern when it is involuntary, unplanned for, or unpredictable. This concern has deepened following the passage of the National Energy Policies Act (NEPA) of 1992. Under this legislation, enforced through FERC, third party power producers may demand transmission access from a utility for wholesale wheeling. The retail wheeling issue is left up to the state. Costs incurred by the utility must be charged to the entity requesting wheeling and may not be charged to the utility's customers, either through recovered expenses or through the rate base.

The transmission system becomes the unintentional victim of at least three recent federal act - Public Utilities Regulatory Policies Act (PURPA), NEPA and Clean Air Act Amendments (CAAA) of 1990. Unplanned and potentially unpredictable forced wheeling and access could result from

- Electric wholesale generators requesting wheeling under NEPA
- QF's producing under PURPA
- Wheeling from one air quality district to another to avoid CAAA 1990 violation.

Today there is no clear incentive for investor owned utilities to incur expenditures which could accommodate transmission access and possible retail wheeling by competitive neighbors or new suppliers entering the electricity supply industry. The obligation to ensure reliability and security of service is distributed among all the players, traditional and new, in the power supply game. However, there are no guidelines as to the responsibilities that each player should assume. Some utilities have already disputed that they are willing to allow increased access to their transmission systems provided that it does not degrade reliability and that charges are fair for their native

customers.

Allowing transmission access while preserving fairness is, however, very difficult to implement from both the engineering and economics standpoints, and consequently it is likely that each case could end up in a court. Unless special rulings are made to build beyond the capacity required for non-wheeling operation, or better control technology is made available in the very near future, the integrity of the U.S. power systems will be threatened. Should this happen on a large scale, much of the nation's bulk power system will be poorly managed and maintained, and system reliability and security will be jeopardized.

Non-utility Generators (NUG's) and Independent Power Producers (IPP's)

Central generation made economical sense throughout most of the growth of the utility industry from early 1990's through most of the 1970's. Economies of scale and improvements in technologies resulted in decreasing marginal cost of energy. However, in the 1970's both efficiency and cost of plant became constant or even less attractive with increasing plant size. Independently, the case for large central generation was further hammered by increasing environmental concerns and, almost independently, by a perceived need for national fuel independence brought on by the oil embargo.

These factors resulted in the Public Utilities Regulatory Policies Act (PURPA) in 1978. In an attempt to encourage the use of renewables and increase fossil fuel generation efficiency, PURPA qualified generators (qualifying facilities or QF's), using renewables and/or cogeneration, could sell energy to utilities at each utility's avoided cost. Ultimately, because of the unexpected drop in oil prices, many utilities were stuck with long term contracts that were uneconomical to the utilities and rate payers but encouraging to investors in the QF industry.

Recognizing that traditional utility economics and regulation needed revision, the National Energy Policy Act of 1992 (NEPA) redefined the utility function. This action was referred to as Public Utilities Holding Company Act (PUHCA) reform. As a result, electric wholesale generators (EWG's), not necessarily qualifying under PURPA, can demand access to a utility's transmission system for wheeling and a utility can initiate the purchase power from the EWG's under each state's guidelines.

So through PURPA and even more through NEPA, the door was opened to third party dispersed generation. Gone was the process, traditional for 40 years, of planning and siting large central generation and planning a corresponding transmission system to provide accepted levels of

security and reliability.

Dispersed generation may now constitute a small percentage of system capacity. However, dispersed generation constitutes over 50 % of new capacity additions for some utilities. As the penetration of dispersed generation grows, it is expected that system stability, frequency and other traditional system attributes may be impacted. The present protection and control technology will need to be re-engineered to allow dispersed generation and/or storage to reach it's economic and technical potential.

Many dispersed generation and storage technologies, particularly renewables, are "inertialess", in that they have an electronic interface which excludes the mechanical inertia that traditional power system analysis has assumed. No adequate models exist to determine system response to a heavy mix of inertialess generators.

Even with conventional generation, such as combined cycles and turbines, the EWG is not required to operate under a utility's automatic generation control (AGC). There is no advantage for it to do so because operating in a load following mode usually decreases efficiency and thereby reduces EWG profit. So, without special negotiated arrangements, utilities could be forced to back down their own base loaded units.

It is expected that the growth of dispersed generation and storage will help defer transmission construction during the next decade. However, in some cases transmission may need to be strengthened to insure stability of partially islanded areas of load where dispersed generation has penetrated beyond the point of controllability.

Although utilities depend more and more on NUG's and IPP's for meeting their generation capacity needs, most of the time those units can be neither directly controllable by utilities, nor put on economic dispatch schedules. These units often run as base-load units. Therefore, during off-peak periods, generation from some base-load units may have to back down to meet a generation-load balance. Therefore, it becomes increasingly difficult for utilities to maintain adequate operating reserve while attaining economic dispatch. In this case, a sudden loss of generation could result in a loss of load. In addition, NUG and IPP units are designed to fit the business purpose of selling electric power, but are equipped to provide a limited reactive power control capability. Therefore, if the total generation capacity from NUG and IPP does constitute a large portion of the utility's total installed generation capacity, it undermines the utility's ability to maintain an adequate system voltage profile. Numerous problems in controlling and operating bulk transmission systems could then arise, thereby degrading system reliability and

security.

Integration of Dispersed Storage and Generation into Utility Distribution Systems

During the last several years there has been a great deal of discussion regarding the placement of small generation and storage, either owned by the utility or third parties, on the electric distribution system. The question has become "Can marginal additions of capacity be sited more economically on the distribution system, near load growth, than can additions to central generation?" More recently, another question has arisen "Can dispersed generation provide greater asset utilization of the electric distribution system?"

The issue of dispersed generation has grown through the passage of recent legislation, the PURPA in 1978, and NEPA in 1992, and the changing economics of generation technology. However, just as important is the continuing delamination of the utility industry. Traditionally, and as shaped by legislation, the utility industry has been vertically laminated - a utility controlled the production of power (centrally generated) which was passed through the transmission network to the radial distribution system where it was dropped off to customers. In recent years, increasing third party generation, encouraged by PURPA and attractive economics, and decreasing load growth have shifted the utilities asset base from generation towards distribution.

As a result of these factors, some utilities have formed separate generation, transmission and distribution business units, and some utilities are considering getting out of the generating business altogether. The growth of third party generation and the intricacies of looming transmission access lead make the business of owning and operating the technologically simple, and defensible distribution system quite attractive.

All the above begs the question, "Why not put small, dispersed generation and storage on the distribution system?" That is exactly the question that has been asked, and several studies are underway to determine whether the scheme is technologically and economically feasible.

In light of the experience with third party generators, EWG's and QF's, utilities are considering installing their own dispersed generation and storage as it becomes economical. The advantages seen are (i) the relatively small capital required; generation can be purchased in small chunks to meet current 1.6 % load growth, compared to the 7.7 % growth seen in the 1960's, (ii) the ability to add additional capacity on an area basis, close to the load, relieving transmission constraints, and (iii) economies of mass production have overtaken the economies of scale,

making small generating units highly cost competitive with large central units.

Even though the distinction between transmission and distribution is becoming increasingly blurred with declining focus on central generation, the inherent geometry differences between transmission (networked) and distribution (radial) holds less promise for dispersed generation to be installed on the distribution system. In the near term we can expect increasing numbers of dispersed units on the transmission system, either through special connections to third party generators, or utility owned units in major substations.

Storage offers great promise for area leveling and increased asset utilization of the local energy delivery system. However, storage technology has not matured to the point of being cost effective, and storage is expected to have a smaller, but growing niche application than dispersed generation in the next decade.

The today's distribution systems are designed and operated to deliver power from a single source, usually a distribution substation, to consumers in only one direction. However, the future distribution systems with dispersed generation devices will have many generation sources, and consequently, today's operations and control practices will not be able to accommodate unknown new characteristics that will be introduced by the new distribution system structure. Preliminary studies have shown that numerous protection and control problems would arise due to the presence of dispersed generation and storage devices. In addition, a new form of stability and operability problems is also expected to arise.

It seems that the impact of these new generation sources on bulk power system operations would be minimal as long as the total capacity of the new sources is small compared with that of the existing facilities and the load level. However, as the penetration level of the new dispersed sources increases, controllability and operability of bulk power systems will be restricted. For example, certain new dispersed generation devices may not be dispatchable, and their generation output has virtually no load following capability. As a result, load frequency control of a utility power system becomes difficult, and a loss of load may take place unless utilities maintain unnecessarily high operating reserve. Therefore, to incorporate the increasing number of dispersed generation and storage devices into the utility's power system, new operations and control technologies need to be developed in order to preserve system reliability and security.

EMF and Right-of-way Limitations

Concern over electric fields became apparent in 1974 in New York during hearings on proposals

to build two 765 kV transmission lines. The evidence cited was a 1960's Russian study reporting illness in switchyard workers exposed to high electric fields. A number of investigations were begun by Edison Electric Institute (EEI) and later by the Electric Power Research Institute (EPRI) to determine the cellular mechanism and health effects of high electric field exposure. None of these studies were conclusive. However, having looked at the evidence available, an independent science advisory panel in Minnesota concluded that there was no scientific basis to believe that power lines proved a hazard to human or other animals.

Electric fields cannot penetrate more than a few millimeters into biological tissue. However, magnetic fields do reach deep tissue and organs. So, in 1979, when two Denver area studies showed a weak correlation between childhood cancer and magnetic field exposure, the EMF issue began to attract broader scientific inquiry and corresponding public concern. Some investigators even began to develop physical models for the interaction of low frequency magnetic fields and cell physiology.

At present there is no way to satisfactorily demonstrate to the public that there is no danger posed by existing exposure to EMF, nor is there a biological model adequate to determine safe guidelines. As a result, the evidence submitted to regulatory agencies consists mainly of anecdotal and weak statistical evidence. The National Energy Policy Act of 1992 includes a five-year, \$65 million federal-nonfederal R&D program giving DOE overall responsibility for EMF research. However, as one DOE official recently put it "There's no end in sight to the controversy - we will never prove there is no ill effect."

As environmental concerns such as EMF are more publicized, it becomes more difficult to site and build transmission substations and lines. To avoid long delay in getting necessary permits for acquiring new right-of-way (ROW), lines are often double-circuited to utilize the existing ROW. Consequently inclement weather or accidents can cause greater disruption on transmission systems since an outage would often mean a double contingency. Also to avoid building new transmission lines, utilities are attempting to load the existing transmission systems to their full capacity. Flexible A C Transmission Systems (FACTS) are being studied and developed to achieve this goal. This, however, will continuously reduce transmission system operating margin, which will ultimately lead to degradation of bulk power system reliability and security.

Clean Air Act Amendments

The Clean Air Act Amendments of 1990 has the goal of reducing annual sulfur dioxide emissions by 10 million tons and annual nitrogen oxide emissions by 2 million tons from 1980

levels for all man made sources. Of course, fossil electric generating units, both utility owned and non-utility owned, will be primary targets of this legislation. The law provides a limited source of emission allowances for all generating units. The process differs between utility and non-utility generators and the available literature does not yet agree as to whether both ownerships have equal access. Allowances can be purchased, traded or pooled within specified regions.

Continuous emissions monitoring systems (CEMS) will be required by 1995 to insure that plants within a control region are operating within their allowances. In many cases this will lead to cleaner plants being operated at fuller capacity while plants producing higher emissions per kW will be backed down. It is uncertain how this process will interact with conventional economic dispatch and automatic generation control. Nor is it certain how negative effects on the transmission system, designed to operate under expected economic dispatch and resulting power flows, will be mitigated.

It is clear that improved real time control, communication and data availability will be necessary for the industry to operate under the new regulations. This need arises because the industry does not yet have the experience to develop predictable emissions dispatch plans. Nor do we have enough plant operating data to form such plans. An example has been given where 7 plants reduced SO₂ and NO_x emissions by 40 % by phone calls to the operators from someone monitoring the CEMS.

There is no question that stability, reliability and other transmission system attributes will be impacted by new dispatch strategies. Plants will be dispatched to meet the requirements of emission credit banking, inter-utility pooling to trade credits, and continuous emissions monitoring, while trying to approach economic dispatch. The resulting complexity will require utilities to operate transmission systems outside of scenarios considered by the transmission planners. In some cases, in an attempt to meet the emissions standards, operators may be forced to operate the transmission system in a manner that violates accepted loading standards, contingency requirements or that otherwise degrades system security. In a few cases, we expect that construction and/or reinforcement of transmission lines will be required.

Design Certification on Standard Nuclear Power Plants

This and next issues are concerned with the continued operation of existing nuclear plants and the construction of new nuclear plants. Change in the continued operation of existing plants is somewhat remote. Standardized plant certification, with one stop construction and operating

permitting, is coming. So the skyrocketing, underestimated nuclear construction costs of the 1970's and 1980's could be mitigated somewhat if any utility decides to build another nuclear plant. Plentiful nuclear fuel, cheaper construction, and standardized permitting aren't enough, say some experts, to revive the nuclear industry. The risk is too high, and the competition, fossil fuel, is too cheap.

The issue of standardizing nuclear power plants is crucial for revival of the nuclear power industry. Because of numerous additional safety features and extensive modifications required by NRC, economics of building nuclear power plants may no longer be advantageous to that of building coal-fired plants. Of course, it is also going to be more expensive to construct coal-fired plants due to the Clean Air Act Amendments. Although this issue is extremely important for the U.S. electric utility industry, it is an economic issue. Furthermore, in case that the issue cannot be resolved, there exists an alternative solution - building fossil plants. Consequently the issue is classified as non-critical as far as maintaining the reliability and security of the US power system is concerned.

High- and Low-level Nuclear-waste Repository Site

Like the design certification issue of standard nuclear power plants, this is a vital issue for revival of the nuclear power industry as well as continuous operation of existing nuclear power plants. Barring a major accident, waste disposal remains the major unknown. The DOE has a deadline in 1998 to begin receiving commercial spent fuel. On the other hand, it is estimated that the earliest likely date for the opening of a spent fuel repository is 2010. Toward that end, nuclear utility rate payers are taxed at one mill per kilowatt-hour to build a nuclear waste fund. About one half of the \$7 billion collected so far has been spent on environmental studies, the most current being the Yucca Mountain site in Nevada. Some utilities, discouraged at the government's progress on this issue, have proposed focusing on building safe plant site repositories. The consensus is that storage will be provided by 1998, but no one knows how.

Under the extreme-case scenario that existing nuclear plants may have to be shut down because of shortage of nuclear-waste repository sites, it would cause a severe shortage of generation capacity to meet the U.S. electricity demand, leading to degradation of the reliability and security of the nation's power system. However, many nuclear power plants have their own temporary nuclear-waste repositories within the plant sites, and political and sociological pressure would not likely to let this possibility happen on a large scale. From the long-term standpoint, since generation options other than nuclear power are available, the issue is not

expected to greatly affect system reliability and security over the next decade.

Industry Restructuring/PUHCA Reform

Many of the elements of this issue have been touched on in issues such as Transmission Access/Retail Wheeling, NUG's and IPP's, and Integration of Dispersed Storage and Generation into Utility Distribution Systems, which have been discussed earlier.

Historically, particularly since the legal establishment of the utility industry, the generation, transmission and distribution systems developed together. As the transmission system became more networked, the major, if not the only, control of power flow through the transmission network was through the control of both generator and transmission equipment. Now, however, a series of legislative acts have begun to delaminate the utilities in an attempt to spur competition. The latest has been the NEPA of 1992. Now, conceptually and politically at least, generation and transmission are considered as independent functions. Still, the planning and operating dependence between the two systems, determined by physics, remains unchanged.

Taken to the extreme, consider a system composed of a number of independent power plants randomly connected to an independently designed transmission network. The security and availability of the resulting system would not be known a priori based solely on the attributes of the generation system or the transmission system alone. The point is that for utility delamination to work to any degree, some minimum set of data describing system attributes will have to pass between the transmission and generation entities. Going further, the communicated data will need to be processed and used to change attributes so that the two systems can operate in an integrated manner. Simply put, the absence of integrated planning will itself require integrated operating.

Therefore, a new form of strategic planning may have to be developed to accommodate any requirements resulting from the PUHCA reform. However, the extreme scenario is not likely to happen within the next decade, and the issue is classed as non-critical.

Long-term Stability of Natural Gas Price

Utility's resource planning is very much affected by a long-term outlook of fuel costs. In particular, optimum generation mix is greatly influenced by natural gas price. In the absence of new nuclear plants and with the leveling off of contributions by renewable power sources and demand side management, a sharp upturn in natural gas prices could be disastrous to the nation's

power supply. The Clean Air Amendments Act of 1990 could increase the use of clean natural gas, as opposed to coal, during the next decade. Still, the experts continue to predict a constant, if not growing "gas bubble" for the foreseeable future. Although gas supplies will eventually deplete, we don't find evidence showing this to be a threat to power system reliability and security during the next decade.

Time-of-use and Place-of-use Pricing

Time-of-use (TOU) pricing came of age in the 1970's and 1980's in an attempt to level the system load through offering separate on-peak and off-peak rates. The analysis became politicized through the regulatory process and to this date no consistent data exists on price elasticities among customer classes. None the less, large commercial and industrial customers have responded, changing their operations to take advantage of the TOU tariffs. Ironically, even though the TOU pricing could benefit system peaks, they could also simultaneously increase local peaks on the distribution and subtransmission systems. Until recently, utility economics has been primarily concerned with generation costs, but with asset shifts to the distribution system, the impacts of TOU pricing on distribution system asset utilization has come under scrutiny.

Experts don't agree on the best deployment or ultimate benefits of TOU pricing. It doesn't seem to be reliable means of controlling transmission system loading. Nor does it seem to be a particular threat to system security at this point.

Place-of-use (POU) pricing uses transportation and other costs to differentiate rates between customers at different points on the delivery system. A customer located further away from the generation source occurs more losses (and perhaps more construction, maintenance and operation costs) for the same energy delivered to his neighbor located near the plant. On the other hand, a customer at the end of a distribution feeder suffers more outages and poorer power quality than he would living near the substation.

These DSM programs can be considered to be a passive approach from the electric power system standpoint, and they are not expected to directly impact system reliability and security.

Quality of Power Supply

Due to proliferation of high technology electronic equipment use, disturbances such as spikes and momentary outages that used to be tolerable are no longer acceptable to consumers. Some utilities have installed power quality disturbance monitoring systems at key locations on their

transmission and distribution systems to measure voltage sags, surges, and impulses. However, the power quality problem is not expected to cause system reliability and security on a large scale, and therefore, the issue is classified as non-critical.

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