Chapter 4

Power System Technology

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Chapter 4
Power System Technology

INTRODUCTION

An electric power system is a vast, complex machine composed of a large number of generators, transmission lines, distribution systems, and substations. Although less physically obvious than generators and transmission lines, systems to coordinate the operation and planning are also vital components without which power systems could not function. Coordination systems include monitoring and communication equipment, devices that actually control generators and transmission lines, and engineering models and expertise which specify how to operate generators and transmission lines as well as plan equipment additions.

As discussed in chapter 1, the demands on power systems are changing. Electricity generation is becoming increasingly competitive, with new forms of ownership and control, and some new technologies are being introduced. Both generators and purchasers of power are seeking greater access to transmission. Utilities are pursuing new methods to reduce costs by improving operating efficiency.

Improving operating efficiency, integrating competitive power supplies, and wheeling power require modifications of uncertain technical feasibility and economic merit. Can a power system operate with many separately owned generating companies and power purchasers demanding access? Is there sufficient transfer capacity to accommodate the changes? What will be the impact on reliability and efficiency?

The physical principles of electricity greatly complicate answering the technical questions. Because power flows at nearly the speed of light with virtually no storage of electricity in a system, the supply of power must balance customer demand at every instant. Also, the flow of power on individual transmission lines is difficult to control. Consequently, the performance of all components is highly interrelated. For example, a generator failure instantly alters the power flows on transmission lines, perhaps beyond safe physical limits, while requiring that other generators immediately increase output to meet demand. Due to the highly integrated nature of power systems, answering the technical questions requires examining the overall power system and the role played by each of the major components.

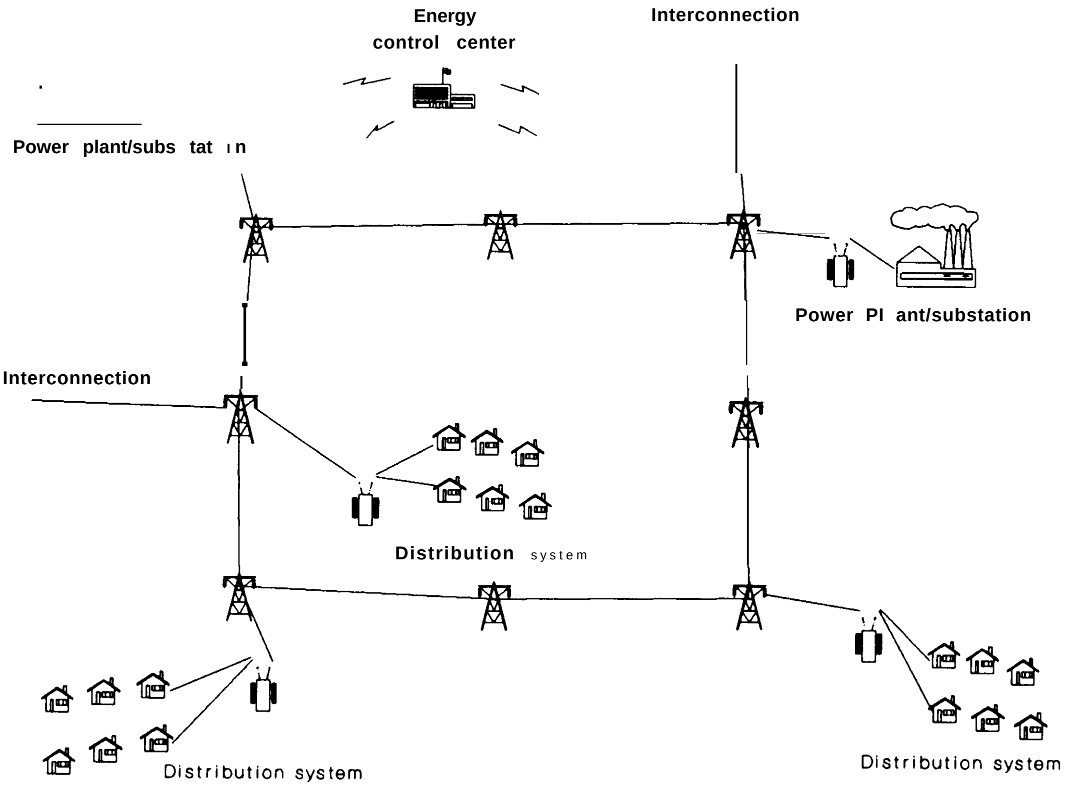
Chapter 4 examines current and future power system technology, and the opportunities to increase transfer capabilities and operating efficiencies of existing systems. The first section discusses the fundamentals of power systems—the equipment that composes the system and their performance requirements. The second section examines the functions involved in coordinating all the individual generators and transmission components into an integrated bulk power system. The last section examines the physics of power transfers, and opportunities to increase transfer capability.

OVERVIEW OF POWER SYSTEM EQUIPMENT

An electric power system is comprised of the major pieces of equipment we commonly associate with the utility industry. This equipment includes *generating units* that produce electricity, *transmission lines* that transport electricity over long distances, *distribution lines* that deliver the electricity to customers, and *substations* that connect the pieces to each other. The *bulk power system* includes the generating plants, transmission lines, and their associated equipment. *Energy control centers co*ordinate the operation of the bulk power system components from moment to moment and prepare for the near future. A wide variety of other planning and engineering systems coordinate operating and capacity expansion plans for the longer term. Figure 4-1 shows a simple electric system with two power plants and three distribution systems connected by a transmission network of four transmission lines.

The U.S. power industry uses a variety of fuels and technologies to generate electricity. Nuclear fission, fossil fuels, and falling water are all commonly used to drive *electric generators* which convert mechanical energy into electricity. Conventional generators typically produce 60 cycle/second (Hertz or Hz) alternating-current (AC) electricity with voltages between 12 and 30 kilovolts (kV). The 60 Hz power is generated in three time-varying

Figure 4-l-A Simple Electric System



SOURCE: Offices of Technology Assessment, 1989.

sinusoidal patterns, called *phases.* Generating units have *automatic voltage regulators* which control the unit's voltage output and *speed governors* which adjust power output and frequency in response to demand and changing system conditions.

A wide and growing variety of unconventional generation technologies have been developed, too. These include cogeneration, conversion of solar energy to electricity, wind-driven generators, and unconventional fuels such as waste material. The mix of fuels and technologies changes from year to year as new units are built and old units are retired.[1]

A *generation substation* connects generators to transmission lines. To minimize losses over long distances, transmission lines require high voltages, typically between 69 and 765 kV. *Power transformers* at the substations raise the voltage to these high levels for efficient transmission. Substations also house a variety of equipment for monitoring and communication and for controlling and protecting both the transmission and generation facilities. A *power plant* consists of one or more generating units on a site together with a substation.

Transmission lines carry electric energy from the power plants to the distribution systems. Most transmission in the United States consists of overhead AC lines operated at 69 kV or above. Often, lower voltage transmission lines operating at between 23 and 138 kV are termed *sub transmission,* although the distinction depends on the characteristics of the individual utility system and is not uniformly applied.

[1]See ch. 6 for a breakdown of the mix of generating capacity.

Power actually flows along bundled strands of wire called *conductors.* Conductors are bare metal cables, typically aluminum strands around a steel core. AC transmission lines typically have three individual or paired conductors to carry three-phase power. There are some segments of direct current transmission and underground cables for special applications, although these are less common than overhead AC lines. Figure 4-2 shows a typical transmission line, consisting of a *right-of-way, towers to* support the conductors, the conductors themselves attached to the towers by *insulators,* and additional *shield wires* to protect the conductors from lightning.

The width of the right of way and the tower design are determined by the voltage of the line and the need for air insulation to prevent electricity from flashing over (i.e., arcing between a conductor and the ground or the tower). Towers may be made of wood, concrete, steel, or aluminum depending on the number and weight of conductors, the terrain, and the distance between towers. In addition to the weight of the conductors, the towers must be able to support any ice which forms on the lines and the force of wind. Typically, high-voltage lines have numerous heavy conductors, requiring use of metal towers for strength.

Figure 4-2-Transmission Line

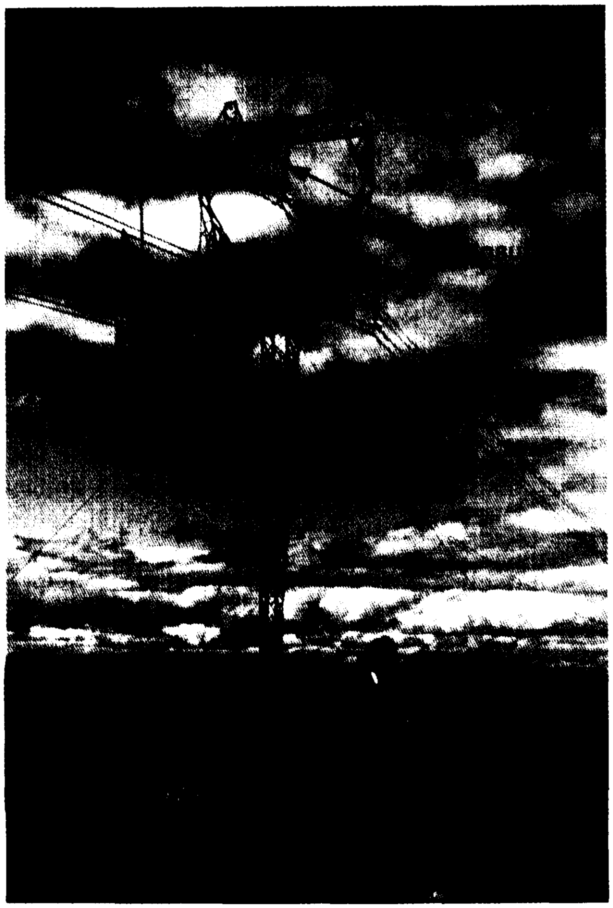


Photo credit: Cassaza, Schultz & *Associates, Inc*

In addition to the conductors and towers themselves, transmission systems have monitoring, control, and protective devices much like those found in power plant substations. *Transmission substations* house this equipment together with devices used to regulate voltage and power flow on the lines.

An interconnected group of individual transmission lines comprises a *transmission system.* A transmission line connected at both ends to other transmission lines is part of the *grid* or *network.* Transmission lines connected to the grid at only one end, with the other end connected either to a generating plant or customer loads, are called *radial* or *feeder* lines. The transmission system shown in figure 4-1 allows each distribution system to receive power from either of the power plants. Even if one network line is disconnected, each distribution system can still receive power from both generators.

Some very large electric consumers, such as major industrial plants take their power directly from the transmission system, typically at subtransmission voltage levels between 23 and 138 kV. A substation containing metering, protective, and switching apparatus connect these large customers to a transmission line. Most customers, however, receive their electricity from a distribution system.

Distribution systems operate at lower voltages than the transmission system, typically under 35 kV, to transport smaller amounts of electricity relatively short distances. Power transformers reduce the high-voltage electricity from the transmission system to the lower distribution system level. The power transformers are housed together with control and protection devices in *distribution substations.*

The distribution system is divided into *primary* and *secondary* systems. The primary distribution system operates at between 2.4 and 35 kV. Some moderately large customers, typically industrial or large commercial, take their electric service from the primary system directly. Most customers receive their electricity from the secondary distribution system at voltages between 110 and 600 volts. The primary distribution system delivers power to distribution transformers which reduce voltage to the secondary system voltage levels. Secondary distribution systems typically serve groups of customers in neighborhoods. Unlike transmission lines, secondary distribution systems typically carry single phase rather than three phase power. Primary distribution may be either single or three phase.

Protective apparatus in the distribution system include circuit breakers in distribution substations that open automatically when a protective relay detects a fault (or short circuit) and fuses on the secondary systems that open when overloads occur. Many of the circuit breakers and switches in distribution circuits are manually operated devices, so restoring service after outages occur is usually done manually.

Nearly all electric utilities in the United States are connected to neighboring utilities through one or more transmission links, or *tie lines.* Each utility is responsible for providing the power used by its customers without taking power from neighbors unless alternate arrangements have specifically been made. Coordinated operation of interconnected systems is implemented through the institution of *control areas.* A control area is a geographic region with an *energy control center* (ECC) responsible for operating the power system within that area. The control area is defined electrically by telemetering equipment on all transmission paths into and out of the area. One or more utilities may makeup a control area. The control area in figure 4-1 is interconnected to two neighboring control areas through transmission lines.

Energy control centers employ a variety of equipment and procedures: monitoring and communication equipment called *telemetry* to constantly inform the center of generator output and system conditions; *computer-based analytical and data processing tools* which together with engineering expertise specify how to operate generators and transmission lines; and governors, switches, and other devices which actually control generators and transmission lines. The control center equipment and procedures are typically organized into three somewhat overlapping systems which are sometimes integrated in a full *energy management system* (EMS). They are the *automatic generation control* (AGC) system which coordinates the power output of generators; the *supervisory control and data acquisition* (SCADA) system which coordinates transmission line equipment and generator voltages; and advanced applications, such as analytical systems to monitor and evaluate system security and performance, and plan operations.

COORDINATED OPERATIONS AND PLANNING

The electric power system is a complex entity comprised of many interacting electrical and mechanical parts. Utilities may have a dozen or more generating units and transmission lines, and hundreds of distribution systems serving hundreds of thousands of customers each with a variety of energy using devices. Coordinating the operation and planning of a utility's equipment to meet the demand for electricity is the responsibility of operating and planning systems. The integrated operation and planning of modem power systems represents decades of evolution and development.

Performance Standards

One underlying goal in planning and operating a power system is to provide electricity that meets customer requirements safely and reliably. This entails:

- providing electricity with the correct voltage and frequency to operate consuming equipment; and
- providing that power with an acceptable level of outages or service interruptions.

In practice voltage, frequency, and reliability maybe viewed as constraints or standards which must be met.

Frequency Standards

A relatively constant frequency of 60 Hz is taken for granted in the design of customers' equipment such as motors, clocks, and electronics. Actual frequencies in U.S. power systems rarely deviate beyond 59.9 and 60.1 Hz, well within the tolerance of consumers' electronic equipment and motors.[2]

Some clocks work by actually counting the number of cycles (i.e., every 60 cycles is 1 second). Keeping correct time requires that total deviation from 60 Hz over time is small and balanced. For example, when frequency fluctuates, clocks slow down or speed up accordingly. Later, the frequency must be adjusted to correct the time. The total deviation, called *time error, is very* small and insignificant.

Power system equipment itself is more sensitive to frequency deviations than consumer equipment. In particular, the control systems of modem power systems are designed to be extremely sensitive to frequency deviations. To function, the control systems actually require very slight deviations and must closely monitor time error. (The slight frequency deviations are essentially used for communication between generators and the control system, as discussed later.) For this reason, standards for frequency are set by the utilities in designing their controls, and frequency fluctuations have virtually no consumer impact. Standards for frequency and time error are set by the Operating Committee of the North American Electric Reliability Council.

Besides maintaining a relatively constant system frequency around 60 Hz, another frequency requirement is to avoid *nonsystem frequencies.* Some electrical equipment creates nonsystem frequencies besides the normal 60 Hz power, which may propagate through a transmission or distribution system and damage other equipment.[3]

For example, harmonic frequencies, i.e., integral multiples of 60 Hz such as 120 or 180 Hz, superimposed on the desired frequency may cause communication equipment malfunctions. Standards for nonsystem frequencies have not been uniformly established, partly because severe problems have been limited.

Voltage Standards

Unlike frequency, which is the same at all locations in a power system voltage varies from point to point. The voltages throughout a power system depend on the voltage output of individual generators and voltage control devices and the flows of power through the transmission system.

Some voltage standards for power delivered to customers are widely accepted and published by the American National Standards Institute (ANSI) (see table 4-1).[4] These standards are given both for normal, sustained conditions and for emergency conditions lasting a few hours. The less stringent shorter term standards allow system operators greater freedom in responding to emergencies. The selection of voltage standards for delivered electricity reflects an implicit balance between the cost of maintaining the standard and consumers' benefits.

The ANSI voltage standards have been developed because many types of customer equipment require certain minimum standards to function properly. For example, with excessively low voltage, electric motors function poorly and may overheat and lights dim. Overly high voltages, on the other hand, shorten the lives of lamps substantially and increase motor power which may damage attached equipment.[5]

Not all equipment has narrow voltage tolerances, however. Electric resistance space and water heaters work well over a wider range of voltages and are insensitive to fluctuations, for example.

The ANSI voltage standards do not apply for short-term voltage fluctuations lasting a few seconds or less. Switching transmission lines and generators on or off and turning on major appliances may create voltage spikes or drops. Voltage fluctuations may damage computers and other electronic equipment or cause lights to flicker. However, standards for short-term fluctuations are far less uniformly established than those for longer term voltage variations.

[2] *Standard Handbook of Electrical Engineering,* Donald Fink (cd.) (New York, NY: McGraw Hill, 1978), pp. 20-46.

[3] *Handbook of Modern Electronics and Electrical Engineering,* Charles Belove (cd.) (New York, NY: John Wiley & Sons, 1986), pp. 2318-2319. E.F. Fuchs, D.J. Roesler, and F.S. Alashhab, *Sensitivity of Electrical Appliances to Harmonics and Fractional Harmonics of the Power System's Voltage,* Parts 1 and 2, IEEE Transactions of Power Deliver, vol. PWRD-2, No. 2, April 1987.

[4] American National Standards Institute, *National Electrical Safety Code—1987 Edition,* ANSI C2-1987.

[5] D. Fink, op. cit., footnote 2.

Table 4-1-ANSI Standard Voltage Limits

	Voltage limits (in percent of nominal)			
	Normal operating conditions		Emergency conditions	
Nominal voltage	Minimum	Maximum	Minimum	Maximum
120-600	95	105	91.7	105.8
600-34,500	97.5	105	95	105.8

SOURCE: Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access, and Non-Utility Generation, " contractor report prepared for the Office of Technology Assessment, March 1986, pp. 1 14.

Some industrial customers have installed their own protective gear to guard equipment against out of range voltages. With the proliferation of computers and other sensitive electronics, an increasing number of customers are purchasing protective devices which filter out voltage fluctuations.

Reliability Standards

Reliability is a measure of the ongoing ability of a power system to avoid outages and continue to supply electricity with the appropriate frequency and voltage to customers. In contrast to the standards for voltage and frequency, reliability goals reflect customer preferences for the trade-off between electricity prices and outages rather than the actual design and operating requirements of customer equipment.

Establishing objective, quantitatively derived standards that accurately reflect the value of service reliability has proven difficult. Ideally, standards should balance the customers' value placed on reliability with the costs of providing it. However, determining the value of reliability to customers has proven challenging because of the wide variance in customers' costs from an outage. Customer outage costs depend on a host of diverse factors including:

- the magnitude of the outage (the total amount of energy or power not supplied);
- how often outages occur, and the duration of the outage;
- how prepared the customer is;
- the type of customer (e.g., industrial or residential); and
- the time of day, day of week, and season of the outage.

Determining the cost to a utility of providing increased reliability is similarly challenging. Bulk system outages occur when generation and transmission are insufficient to meet total customer demand at any instant. However, neither loads nor the availability of generation and transmission can be forecast with great accuracy. In particular, relatively infrequent and unpredictable events (e.g., a lightning strike on a transmission line or sudden equipment failure) may suddenly reduce the availability of a critical generator or transmission line. Also, analyzing the joint reliability impacts of transmission and generation is challenging. Thorough examination of the complex interactions between individual power system components under the nearly endless array of possible conditions is analytically intractable. As a result, it is difficult to calculate the improved reliability resulting from adding new generation or transmission equipments

Further, even with high *bulk system* reliability, a large number of outages may occur. In fact, bulk system failures account for a relatively small portion of customer service outages, around 20 percent by one estimate.[7] The remainder is caused by distribution system problems, often the result of storm damage to distribution lines.

In lieu of more quantitatively derived and defined standards for reliability, engineering planners as-

[6] For a comprehensive discussion of the challenges of evaluating reliability impacts focusing on the challenges of integrating generation and transmission effects, see Public Service Electric & Gas Co., *Composite System Reliability Evaluation: Phase 1, Scoping Study,* Electric Power Research Institute, EPRI EL-529(I, December 1987.

[7] U.S. Department of Energy, "The National Electric Reliability Study: Executive Summary," DOE/EP-0003, April 1981, as cited in: *Power System Reliability Evaluation*, Institute of Electrical and Electronics Engineers, 1982, p. 42,

sume a variety of rules of thumb or de facto standards. Three of the most common reliability-related goals are:

- loss of load probability (LOLP) of 1 day in 10 years,
- first (or second) contingency security, and
- reserve margins of 15 to 20 percent. (See box 4-A.)

These reliability standards specify the amount of capacity to be installed (e.g., reserve margins and LOLP), and how that capacity must be operated (contingency security). Thus, they play a central role in determining the constraints and capabilities of modem power system operations and planning.

While these indices are all commonly used, there are no uniform definitions of how they are calculated, in part due to the variety of conditions important to different utilities. For example, in calculating LOLP or reserve margins, a utility relying heavily on power imports may include the impact of transmission while other utilities do not. The choice of standard to attain is a matter of experience and engineering judgment as well as system specific characteristics and is not uniform across the country.[8]

Many parts of the country currently have higher bulk system reliability than that prescribed by the standards. The exceeded standards result from the current surplus capacity planned and built to meet high-load forecasts of the past two decades that did not materialize.

Whether current standards could be strengthened or weakened to the benefit of customers is speculative. Certainly, some customers may benefit from reduced reliability if accompanied by reduced electric prices, just as others may prefer higher reliability even with higher prices.

Operating and Planning Requirements

Given the performance standards for delivering electricity, there are three general functions for coordinated operating and planning, They reflect the dynamic and complex nature of power systems and their customers. The functions are:

1. following changing loads;
2. maintaining supply reliability; and
3. coordinating transactions of power.

In practice, operating and planning systems seek to perform these functions at minimum cost. This requires a tremendous amount of information, computing power, and communication capability, as well as extensive coordination within and among the various organizations involved.

Following Load

At each moment the supply of power must equal the demand of consumers. However, demand changes continuously and occasionally unpredictably. Some load patterns tend to repeat approximately with the time of day, day of week, and with the season. Figure **4-3** shows a weekly pattern of demand for a U.S. utility. The vagaries of weather, economic conditions, consumer behavior, and in the longer term, technological change all impede the ability to forecast accurately. The continual and sometimes unpredictable changes in demand require coordination systems to be able to follow loads from moment to moment (called *regulation)* and from hour to hour (called *ramping) as* well as plan supplies flexibly for the longer term.

A fundamental constraint in following loads involves ensuring that generating units and transmission equipment operate within design tolerances. For example, power system equipment used for generation, transmission, and distribution has certain voltage requirements, much like consumer equipment. Standards for power system voltages are set by system engineers based on site-specific equipment design and operating requirements. Some power system equipment requires voltages within fairly narrow tolerances to operate properly. Other power system equipment particularly some transformers, are designed to function over a wide range of voltages. Similar constraints apply to the ability of transmission equipment to accommodate power flows. The capabilities and constraints of power system equipment are discussed in greater detail later in this chapter.

[8] See ch. 6 for a discussion of standards in different regions.

Box 4-A—Three Common Reliability Standards

Loss of Load Probability (LOLP)

LOLP is a measure of the long-term expectation that a utility will be unable to meet customer demand. Many utilities prescribe a standard LOLP of 1 day in 10 years. This means that given the uncertain failure of generation and transmission equipment and variations in customer demands, engineering analyses predict that there will be a bulk system outage for 1 day in a l0-year period.[1] The LOLP specifies neither the duration of the outage (e.g., whether the outage lasts several seconds or an hour) nor the magnitude (whether the outage affects one distribution substation or the entire system). Different utilities use different definitions of LOLP; there is no single consistent method of calculating it.

Contingency Security Criteria

After a major system component such as a generator or transmission line has failed, the redistribution of power flow on the remaining system will not automatically meet customer load. Even if sufficient generation is available, voltages and thermal loadings on the transmission system may fall outside acceptable limits, or the system may be unstable resulting in cascading failures. Utilities typically specify a reliability criterion of first (or second) contingency security, meaning that sufficient reserves of transmission and generation are immediately available such that the power system will continue to operate even if the one (or two) most critical components fail.[2] This is called the principle of **n-1** (or n-2) operation, and applies at all times, even when some elements are already out of service. For example, if three lines are out of service, the system's operation must be adjusted so that it will be able to stand the loss of a fourth line, Usually the critical components are the largest generators or transmission lines, or some component at a critical location in the network. In general, contingency studies assume that no more than one or two major failures will occur at a time (multiple failures are improbable unless there is some common cause). Contingency studies rely upon engineering judgment to decide which types of failures are reasonable or credible, since the large number of components makes enumerating all possible failure modes impractical.

Capacity or Reserve Margin

The reserve margin is the oldest and most traditional measure of reliability. Reserve *margin* is the difference between generating capacity and peak load expressed as a percentage of peak load. Similarly, ***capacity margin*** is the difference between capacity and peak load expressed as a percentage of ***capacity*** (rather than peak load).3 Thus, for example, a system with a peak load of 4,000 MW, and installed capacity of 5000 MW has margins of: Reserve Margin = (5,000-4,000)+ 4,000= 0.25, or 25%; and Capacity Margin = (5,000-4,000)+ 5,000= 0.20, or 20%. The numerator for both measures is the same, but the denominator for is capacity margin is smaller, so the capacity margin is always smaller than reserve margins by a few percentage points. Capacity margin is the measure used by the North American Electric Reliability Council, although in practice most utilities refer to their reserve margins. Typically reserve margins of about 15 to 20 percent have been considered sufficient to allow for maintenance and unscheduled outages (corresponding to capacity margins of approximately 13 to 17 percent).[4] However, the amount of reserve margin required depends on system specific factors such as the number and size of generating units and their performance characteristics. For example, a system with a few large units will require higher reserves than a system with many small units.[5]

[1] Recall that the bulk power system includes generation and transmission but excludes distribution. Thus, outages are expected to be more common than the LOLP standard indicates.

[2] North American Electric Reliability Council (NERC), *Transfer Capability—A Reference Document* (Princeton, NJ: 1980), pp. 6-7.

[3] Reserve margins and capacity margins are intrinsically related by the equation: Capacity Margin = Reserve Margin + (1 + Reserve Margin).

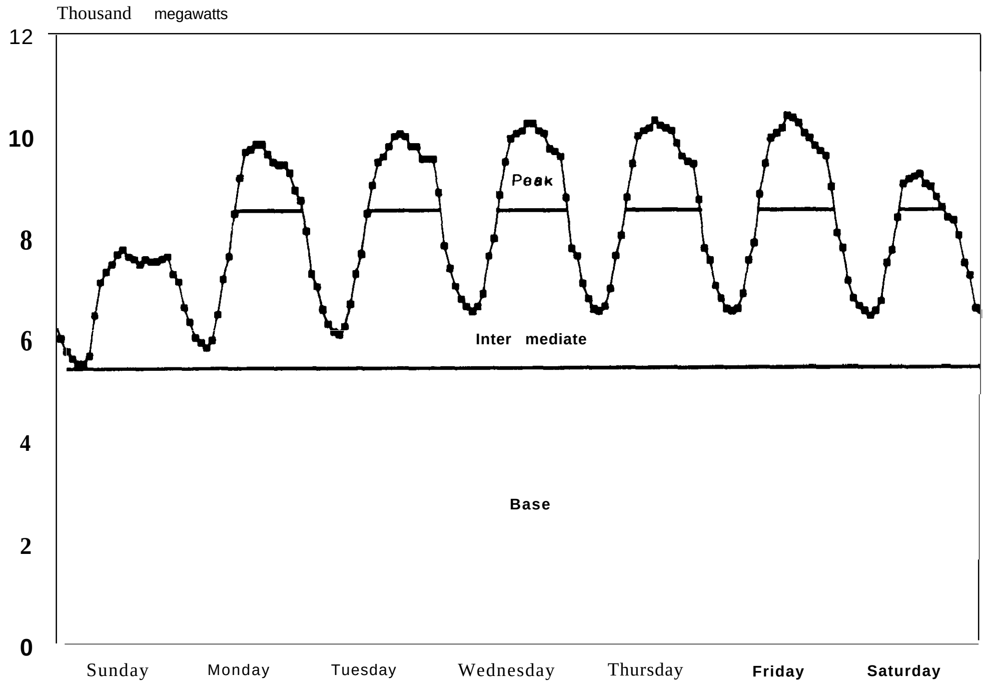
[4] A. Kaufman and K. Nelson, Library of Congress, Congressional Research Service, "Do We Really Need All Those Electric Plants?" August 1982.

[5] North American Electric Reliability Council (NERC), *Reliability Concepts* (Princeton, NJ: February 1985), p. 16.

Maintaining Supply Reliability

The cost and performance of generation and transmission equipment is variable and uncertain, as are customer loads. From one moment to the next, any piece of equipment may fail, either on its own or due to external influences (e.g., lightning strikes). Preparing for continued operation after equipment failure is called maintaining *security*. As defined by the North American Electric Reliability Council

Figure 4-3-Weekly **Load Curve**



SOURCE: Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non Utility Generation," contractor report prepared for the Office of Technology Assessment, March 1988, pp. 2-3.

(NERC), "security is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. "[9]

Ensuring sufficient availability of supplies is called maintaining *adequacy*. Again according to NERC, "adequacy is the ability of the bulk power electric system to supply the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components."[10] In addition to unexpected failure, virtually all equipment requires some maintenance, and has operating limitations that reduce availability. In the longer term, the cost and availability of fuels is uncertain, resulting in uncertain operating costs for generating units. In the longer term still, construction cost and schedules for new equipment are often uncertain, as is the demand for power. Maintaining adequacy involves addressing these cons tints and uncertainties.

Coordinating Transactions

Nearly all utility systems are interconnected with other systems, allowing for a variety of transactions. Transactions may take a variety of forms, including: short-and long-term purchases and sales with neighboring systems; purchases from suppliers within a utility's service area (e.g., an independent power producer); operation of jointly owned power plants; and wheeling of power. *l

[9] North American Electric Reliability Council (NERC), *Reliability Concepts* (Princeton, NJ: NERC, February 1985), p. 8.

[10] Ibid.

[11] For a comprehensive discussion of the types of interutility transactions used, sec: Energy [formation Administration, *Interutility Bulk Power Transactions*, DOE/EIA-0418, October 1983.

Photo credit: Casazza, Schultz & Associates, Inc.

An electrical substation

Except where contrary arrangements are specifically made, it is the responsibility of each utility to provide the power used by its customers without absorbing power from its neighbors or sending unwanted power to them. Through NERC, North American utilities have set standards for controlling inadvertent interchange.[12]

One requirement for inadvertent transactions is based on "area control error" (ACE), a measure of difference between the actual and scheduled interchange at any moment which also accounts for power frequency deviations. NERC guidelines specify both that ACE must be zero at least once in each 10-minute period and must not average beyond a specified level for any period. Controlling ACE and inadvertent power transfers requires careful scheduling and control of transactions between the entities as well as monitoring and recording the transactions for billing or other compensation.

Implementing Coordinated Operations and Planning

Performing the functions of following load, maintaining reliability, and coordinating transactions

[12] North American Electric Reliability Council (NERC), *Operating Manual* (Princeton, NJ: Dec. 1, 1987).

[13] For a more technical description, see example: Institute of Electrical and Electronics Engineers (IEEE) Committee Report, "Description and Bibliography of Major Economy-Security Functions, Parts 1, 11, and Ill." *IEEE Transactions on Power Apparatus and Systems, vol.* PAS-1(M), No, 1, January 1981, pp. 211-235.

involves executing several coordinated operating and planning procedures. 13

The procedures each focus on different time horizons and different aspects of the power system (see table 4-2). Some procedures such as coordinating the energy output of generating units to balance demand are performed continuously. Others, such as planning generation additions, are performed far less often. The time horizon each procedure is concerned with also varies widely. For example, controlling energy input to a generator focuses on a time horizon of under a minute, while long-term planning may have a 20-year or more horizon reflecting the long construction time and useful life of generation and transmission equipment. Each time horizon beyond a few seconds requires forecasts of customer demand and performance of system equipment.

Governor Control of Generators for Load Following

At every moment, the power generated must balance the amount demanded to maintain the 60 Hz frequency required by both customers and the power system. Frequency fluctuations result from an imbalance between the supply and demand for power in a system. In any instant, if the total demand for power exceeds total supply (e.g., when a generator fails, or as demand increases through the course of a day), the rotation of all generators slows down, causing the power frequency to decrease. A similar process occurs in reverse when generation exceeds loads, with the governors reducing the energy input to generators to maintain frequency.

Controlling frequency involves balancing the supply and demand for power. Speed governors on most generating units constantly monitor frequency and regulate those units' power output to help balance demand and restore the frequency. The constant change in a unit's power output slightly increases maintenance requirements, and slightly decreases operating efficiency.

Power output from a generator does not change instantaneously. The rate at which a generator's power output can increase or decrease, called the *ramp rate* or *response rate,* depends on the type of generator. That is, the usefulness of a particular generator in regulating frequency varies from unit to unit. Large steam generating units such as nuclear power plants and large coal units generally change output levels slowly, while gas turbines and hydro units are very responsive. Table 4-3 shows typical response rates for different types of generators. The response rate is expressed in percent of rated

Table 4-2-Operation and Planning Functions

Function	Purpose	Procedures involved
Following load		
Frequency regulation	Following moment-to-moment load fluctuations	Governor control Automatic generation control (AGC) and economic dispatch
Cycling	Following daily, weekly, and seasonal cycles (within equipment voltage, power limits)	AGC/economic dispatch Unit commitment Voltage control
Maintaining reliability		
Maintaining security	Preparing for unplanned equipment failure	Unit commitment (for spinning and ready reserves Security dispatch Voltage control
Maintaining adequacy	Acquiring adequate supply resources	Unit commitment Maintenance scheduling Planning capacity expansion
Coordinating transactions	Purchasing, selling, and wheeling power in interconnected systems	AGC/economic dispatch Unit commitment

SOURCE Adapted from F. Mobosheri, Southern California Edison, letter 10 Office of Technology Assessment, May 13, 19S6.

Table 4-3--Typical Generator Response Rates[a]

Unit type and size	Response rate
Steam units (all fuels)	
10-50 MW	4.8% per minute
60-199 MW	3.8% per minute
200 and over	2.80/. per minute
Hydroelectric	
10-59 MW	1-6% per second
above 60 MW	4-6% per second
Combustion Turbine	
All Sizes	55% per minute

[a]See "Power Plant Response," Institute of Electrical and Electronics Engineers Working Group on Power Plant Response to Load Changes, IEEE Paper TP 65-71, 1965; and *Survey of Cyclical load Capabilities of Fossil Fired Generating Units* (Palo Alto, CA: Electric Power Research Institute, 1979) EPRI-975.

SOURCE: Power Technologies, Inc., "Technological Considerations in Proposed Scenarios for Increasing Competition in the Electric Utility Industry," contractor report prepared for the Office of Technology Assessent, March 1988, pp. 2-16.

capacity per minute or per second at which output can change.

The ramp rate of a generator reflects the *maximum* rate at which the unit's power output can change. Given this upper limit, each generator's governor is set to specify how rapidly and to what extent the unit actually will respond to frequency changes. Some, but not all units need to be on governor control to respond quickly. In fact, some units do not respond at all, but instead are set to produce a fixed power output. The amount of generation under governor control required to follow load depends on expected changes in load and on the ramp rates of the available controlled generators. System engineering analyses determine the amount of generation required to be under governor control. Setting the generator governors is a function with a slightly longer time horizon, discussed next.

Economic Dispatch and Automatic Generation Control for Load Following, Reliability, and Coordinating Transfers

Coordinated operation based on the incremental costs of generation, called economic dispatch, is one key to minimizing cost.[14]

The incremental production cost of a generating unit is the additional cost per kilowatthour (kWh) of generating an additional quantity of energy or the cost reduction per kWh due to generating a lesser quantity of energy. Incremental production costs depend on the cost of fuel and the efficiency with which the unit converts the fuel to electricity, and any other operation costs that vary with the level of power output. In economic dispatch, units with the lowest incremental costs are used as much as possible to meet customer demand. Typically, economic dispatch is entirely recomputed every 5 to 10 minutes.

Automatic computer control of generator output is used to implement the dispatch of generators in a control area. Automatic generation control (AGC) systems calculate what increase or decrease in each generating unit's output is required to maintain the balance between supply and demand in the least costly way. Based on AGC calculations, generator governors are reset to affect the change. An AGC system constantly monitors the power system frequency to determine whether increased or decreased output is required. The AGC system typically resets generator governors every 5 to 10 seconds based on an approximation of economic dispatch.

When governors balance supply with loads, high incremental-cost units such as combustion turbines may be used because they are able to change power output rapidly. The AGC systems set the governors on power plants so that power output from low-operating cost generators increases to displace output from more expensive generators that were used to control frequency.

To perform its job, an economic dispatch and AGC system needs cost and performance information about each of the power system's operable generating units. For example, the system must know the range of power each generator can produce (called the *control range)* and the ramp rate. Typically, the efficiency with which fuel is converted to electricity, and hence the incremental cost, depends on whether the plant is being operated at full or part capacity. Control ranges, efficiency, and incremental costs vary widely with the type of generator, and sometimes on contractual requirements for purchasing power.

[14]See B.F. Wollenberg and A.J. Wood, *Power Generation, Operation and Control* (New York, NY: John Wiley & Sons, Inc., 1983); or A.S. Debs, *Modern Power System Control and Operation* (Boston, MA: Kluwer Academic Publishers, 1988).

Minimizing total cost often involves one utility purchasing electricity produced by another. Interutility transactions are sometimes very highly automated, as in the case of the Pennsylvania-New Jersey-Maryland interconnected system, which is one large control area with 11 member utilities acting as a tight power pool. In other cases, the process is less automated, carried out through brokerage systems or by system operators using telephones or small computer networks to exchange sale and purchase information.

AGC systems control both the planned and inadvertent power exchange between control areas. Interutility transactions are implemented by increasing the generation of the selling utility and decreasing that of the buying utility. When inadvertent, excessive, or insufficient exchanges occur, AGC systems adjust the governors on generating units to increase or decrease power output, correcting the amount of power transferred. To properly control interutility exchanges, AGC systems must have information on the planned schedule of power transfers and must constantly meter the actual power flows for comparison.

In calculating which generating units to operate and at what level, the dispatch system must also consider the effects of the transmission system. Dispatch systems commonly incorporate two principal effects. First, losses on the transmission lines may be significant in systems with widespread generation and loads. When this is the case, the dispatch systems must consider the incremental cost of transmission losses in addition to the incremental operating cost of generation. Accurately calculating incremental transmission losses is difficult and time consuming. however. Losses increase disproportionately with increases in power transfers and depend on the often indirect path of power flows. Both features result in computational difficulty for determining actual losses. However, some consideration of transmission losses is required. Typically, an approximate mathematical model of the losses is used.

The second transmission consideration relates to adequacy and reliability. The capacity to transfer power while remaining within voltage and load flow limits is a constraint on economic dispatch. When sufficient transmission is not available to deliver power from the lowest cost generators to loads, other generators must be operated. This is called operating off-economy. The dispatch system then needs to know not only the capacity of the transmission system and the current use but also the amount of capacity required for the transfer and the effect on system voltages. Again, due to the computational difficulties of calculating power flows, the dispatch system relies on another portion of the energy management system to determine the security (e.g., ability to withstand equipment failure) of the dispatch scheme chosen and override the economic dispatch if needed. That is the function of security constrained dispatch, discussed later.

Voltage Control for Load Following

The job performed by governors and AGC focuses on meeting frequency requirements economically as loads change. However, changing generation dispatch may also change voltages across the system. Voltages must be kept within design tolerances for a power system to provide acceptable service to customers. Maintaining voltage involves balancing the supply and demand of power, although in this case, it involves balancing *reactive* power (called VARs) rather than real power (see box 4-B). An imbalance in the supply and demand of VARs causes voltage to rise or drop across the power system. Understanding the pattern of voltages and reactive power flows is a complicated problem arising from the physics of electric systems.

Power system equipment creates the primary demand for VARs. Long, heavily loaded transmission lines typically consume VARs, as do power transformers and motors. One effect of reactive power flows is that the use of distant low-cost generating units may not be possible if sufficient VAR supplies are not available despite otherwise adequate transmission line capability.

Maintaining voltages to within the standards required by system equipment is the function of VAR control. Voltages at various locations are telemetered to the energy control center from various points in a power system and checked to ensure they fall within the acceptable range. When voltages begin to deviate from the acceptable range, both automatic and remotely controlled actions are taken using a variety of reactive power control devices. Supervisory control and data acquisition

Box 4-B—Real and Reactive Power

Power is the product of voltage (electrical potential or pressure) times current (the number and velocity of electrons flowing). In an AC system, both voltage and current vary sinusoidally over time with a frequency of 60 cycles per second (60 Hertz). However, the current and voltage are not necessarily in phase with each other. That is, the current may reach its maximum slightly before or after the voltage does in each cycle. *Active, or real power* results from current and voltage in phase with each other. Measured in watts, it is the power delivered to a load to be transformed into heat, light, or physical motion. *Reactive power* results from that portion of current and voltage which are not in phase. Measured in V's (for Volt-Amps Reactive), it can be thought of as the flow of power stored (but not consumed) by electric and magnetic fields around circuit components.

That current and voltage may be out of phase results from a phenomenon called *reactance.* ' When a voltage causes a current to begin flowing through a wire, a magnetic field forms around the wire opposing and delaying the change in current. When the voltage is reduced, the collapsing magnetic field again opposes and delays the reduction in current. The magnetic field may also induce or retard a current in nearby wires (e.g., other conductors in a transmission line). The overall effect of the forming and collapsing magnetic fields in delaying changes in current relative to voltage creates *inductive reactance, or inductance.* The larger the current, the larger the inductive effect.

Similarly, different voltages between circuit components (e.g., between conductors in a transmission line or between a conductor and the ground) create electric fields. These forming and collapsing electric fields result in *capacitive reactance* (or capacitance), in which current changes are advanced relative to voltage changes. The larger the voltage, the huger the electric field and the capacitive effect.

Capacitance and inductance exist in any piece of electrical equipment. When capacitance and inductance are balanced in a transmission line the voltage and current are in phase with each other. Then there is no net flow of reactive power. When the inductive effect is greater than capacitive effect the current lags the voltage at any point on the transmission line and the line is said to consume reactive power. Similarly, when the capacitive effect is greater, the voltage lags the current and the line is said to produce reactive power.

A transmission line's operating voltage is determined by the line design, and the capacitive effect is constant. However, different real power flows on a line result from different currents, with fixed voltages. Thus, the inductive effect, due to magnetic fields caused by current flowing, increases as the amount of power flow increases. For this reason, low real power flows on a line may result in a high flow of produced reactive power. High active power flows on a line may result in a high flow of consumed reactive power.

[1] Reactance is one part of the *impedance* to flow determining how much current will flow for a given voltage. The other part of impedance is called *resistance*, which occurs as the flowing electrons collide with atoms of metal in the conductors. Resistance is a form of electrical friction which creates heat.

SOURCE: Office of Technology Assessment, 1989.

systems combine telemetry of voltage to the control center and remote control of VAR supplies.

VARs may be supplied or consumed by generators either automatically or under the control of system operators. Whereas real power output of a generator is controlled by governors controlling the energy input, reactive power is regulated by adjusting magnetic fields within the generators. As with real power, reactive power output from a generator is limited. Limits to reactive power output are due to possible overheating within the generator resulting from high levels of output. Control of generator VAR output and off-economy dispatch are common modes of voltage control on the bulk power system.

Other automatic and manual voltage control devices include capacitors, shunt reactors, variable transformers, and static VAR supplies. These devices may be installed at various locations in the transmission, subtransmission, and distribution systems. Voltage problems resulting from VAR flows are one major cause of transmission limitations. Also, improved VAR control may help reduce operating costs by reducing VAR flows. [15]

[15] Scientific Systems, Inc., *Optimization of Reactive VAR Sources in System Planning,* EPRI EL-3729, November 1984.

As a result, the use of these devices is likely to increase over time. VAR-related transmission limits, and some approaches to reducing them are discussed in the final section of this chapter,

Security Constrained Dispatch for Reliability

The combined control of real and VAR generation output and other VAR sources may not result in secure performance. Maintaining system reliability is the job of *security constrained dispatch* of generation.

The objective of security constrained dispatch is to prevent the possibility of "cascading outages" in which the failure of one or two generators or transmission lines results in the overloading and failure of other equipment. A key to security constrained dispatch is scheduling generation in a "defensive" mode so that the power system will have enough supplies ready to continue operating within emergency standards for frequency, voltage, and transmission line loadings should contingencies occur. In a sense, security constrained dispatch accounts for reliability constraints on transfer capacity.

An important parameter of the defensive operating practice is that transmission capability must be held in reserve for the possible occurrence of a major failure in the system. Generating units are similarly held in reserve. Idle generating units and transmission lines with below capacity power flows may mistakenly seem to be surplus, when in fact they are essential for reliability. This difference between appearance and reality must be carefully noted in changes to the power system.

The analytical methods used are based on load flow calculations of real and reactive power flows in the power system. Control center operators typically examine a series of contingency cases to determine the most severe contingency and the resulting power transfer limit. When that limit is lower than present transfers, the economic dispatch is recalculated to reduce the transfer to acceptable levels and implemented by the AGC and Supervisory Control and Data Acquisition (SCADA) systems. By dispatching generating units "off-economy," security constraints result in higher operating costs.

Power flow and contingency analyses needed for security constrained dispatch are time-consuming and computationally difficult. Complex systems with many generating sources, transmission components, and loads have complicated flow patterns, resulting in a large number of contingencies to be examined. Because of the computational difficulties, security constrained dispatch often relies on planning and analysis to determine transfer capabilities and constraints. The result is an approximation of actual security constraints. Utilities are increasingly developing automatic energy management systems by combining the data acquisition capabilities of SCADA systems with load flow and other analytical tools needed to evaluate security in real time.[16]

Unit Commitment for Load Following, Reliability, and Coordinating Transactions

Generating units typically need to warmup before operating (unlike transmission lines). To be ready for operation, generators must not only be warmed up, but must also be rotating in synchronism with the 60 Hz of the power system. This requires utilities to establish a *unit commitment plan.* Unit commitment plans seek to ensure a sufficient supply of generation for immediate operation in case of contingencies such as failure of a generating unit or transmission line. Also, the plan ensures that sufficient generation under governor control is available for regulating frequency in response to changing loads. Such generation which is synchronized and ready to serve additional demand is called *spinning reserves.*

Unit commitment plans also specify which units will be warmed up and cooled down to follow the cycle of loads over the course of a day, week, or season. Utilities calculate unit commitment schedules which minimize the total expected costs of operation and spinning reserves required to maintain reliability and meet expected changes in demand. Often, utilities also schedule power purchases from other utilities. New unit commitment plans are typically established each day or after major plant outages or unexpected load changes.

Unit commitment planning requires a vast **amount** of information. Virtually all the information about generation and transmission operating cost and

[16] "SCADA/EMS Market Still Vibrant," *Electrical World*, vol. 201, No. 10, November 1987, p. 36.

availability required by the dispatch and security systems is also needed to develop the best unit commitment schedule. In addition, the time and cost to warm up generating units and the availability of personnel to operate generating units must be considered. These factors vary depending on the type of generating unit. Unit commitment schedules are typically developed using computers to perform the numerous calculations for identifying the minimum expected total costs.

Scheduling Unit Maintenance for Reliability and Coordinating Transactions

Scheduling maintenance is similar to unit commitment, although with a somewhat longer time frame. The objective is to schedule needed generation and transmission equipment maintenance to meet reliability goals and minimize the expected cost of operation. Maintenance scheduling requires information about each piece of equipment's need for maintenance, and the expected customer demand. Maintenance schedules may be established annually or following unexpected equipment outages.

System Emergency Operations and Restoring Power for Reliability Emergencies

System emergencies occur when there simply is not enough capacity available either within the utility or through neighboring systems to meet load. When voltages and frequencies deviate too much as a result, relays and circuit breakers may isolate overloaded generators and transmission components from the system, exacerbating the imbalance between supply and demand. Emergency operations involve avoiding cascading outages by reducing the power delivered to consumers. In the extreme, this requires disconnecting customers from the system. Plans for load shedding must be coordinated with the automatic isolation of generating units that occurs under abnormal frequency and voltage conditions. Restoring power also requires coordination of the system components and the devices used to isolate the loads. Following system failures, restoration requires that some generating units be capable of starting on their own, called "black-start capability, " Not all generators have this capability, typically taking their starting power from the system.

Planning Generation and Transmission Capacity

System planning has the long-term focus of adding adequate generation and transmission capacity to meet changing demands reliably and at low cost. Planning begins with forecasting both the changing patterns of demands on the system, as well as the costs of alternate fuels and resources. Based on these forecasts, planners implement generation expansion plans to meet those changing conditions. Plans for new transmission facilities must reflect both the changes in demands and in generation. Planning new generation and transmission facilities is typically a utility responsibility, often performed with considerable regulatory oversight. Also, because of the interconnected nature of utilities, plans are also usually coordinated with power pool and NERC region review to assure reliability.

Uncertainty in forecasting presents acute problems for planning, in which time horizons of 2 to 30 years reflect the construction and operating lives of new generation and transmission facilities. In recent decades, forecasts of long-term load growth have often been highly inaccurate. In addition to uncertainty over long-term trends, load forecasting is complicated by the effects of unpredictable (but inevitable) variations in weather and economic cycles from year to year. Similarly, the significant uncertainty and swings in fuel prices make operating costs highly uncertain. The result of this uncertainty is a mix of facilities which may not ideally meet existing conditions (e.g., with surplus or deficit generating capacity). At any time, the existing mix of generation and transmission capacity reflects previous expectations of fuel prices, construction schedules, and customer demand which may be quite different from actual outcomes.

Generation expansion planners have many supply technologies to choose from, with a wide range of cost and performance characteristics. Typically, generating units with relatively low operating costs (e.g., nuclear, coal, hydroelectric) have been relatively expensive to build and have had long construction periods. Generating units that are relatively quick and inexpensive to build (e.g., gas-or oil-fired combustion turbines) have had relatively high operating costs. Because of uncertain fuel price and availability, planners often seek a diverse mix of generating technologies.

The growing interest in conservation and load management technologies, together called demand side management (DSM), has added further options to expansion planners. DSM has an even wider variety of performance and cost characteristics. Increasingly, system planners must also consider nonutility generation in transmission and generation planning. Numerous computer-based analytic tools have been developed to aid planners in evaluating the financial and economic impacts of different capacity expansion plans under a variety of demand and economic scenarios.

Choice of generation types is often broken into base-load, intermediate, and peaking reflecting the time-varying patterns of demand (figure 4-3). Plants chosen for base-load operation typically have relatively high construction costs justified by low operating costs. Because of the limited hours they're expected to operate, generating units with low capital cost are chosen for peaking duty, even though they may have higher fuel and operating costs.

The varied operating and cost characteristics of different generation technologies give each advantages and disadvantages for use in a power system. System planning must ensure adequate controllable generation for regulating both frequency (by controlling the output of active power) and voltage (by controlling the output of reactive power). The costs and ability to operate as spinning reserves and to warm up or cool down under unit commitment plans are also critical. Table 4-4 summarizes some of the key characteristics considered in planning of both existing and prospective generation facilities.

Transmission system expansion must be adequate to accommodate generating unit additions as well as the changing patterns of loads. Siting of power plants is integrally related to transmission requirements, and costs and capabilities need to be considered together. Depending on the location of a new generating unit relative to the existing transmission system, new transmission may or may not be required. Transmission additions may also be needed to increase transfer capability to neighboring utilities. The appropriate level of interutility transfer capability depends on the opportunities such as exchanging reserve generating capacity and obtaining lower-cost energy and capacity.[17]

A variety of engineering-analytical tools are used to determine the type of transmission additions needed, and the overall impact on the existing system. These tools help planners examine such factors as:

- the effects on real and reactive power flows,
- the resulting transmission losses,
- the need for voltage and reactive power control devices on the system, and
- the transient stability and contingency security of and the impacts on system reliability.

Table 4-5 summarizes some of the key characteristics of both existing and prospective transmission facilities which are considered in planning,

INCREASING TRANSMISSION CAPABILITY

Transmission systems have a variety of uses such as:

- delivering power from a utility's supplies to its customers,
- providing for interutility exchanges of economy energy, firm capacity and shared reserve capacity,
- integrating nonutility generation, and
- wheeling power.

In integrated power systems, performing these functions involves moving power from a large number of generators to a large number of loads along a network of transmission lines. At times, transmission constraints occur which limit the ability to move power from one location to another. This section describes the constraints on a system's transmission capability and some of the technologies available to ease those constraints,

Limits to Transfer Capability

Basic physical principles largely determine the transmission capability of a power system. *A few fundamental factors underlie the physical limitations to transfer capacity of power* systems. The limitations may be due to either the abilities of

17 For a discussion of planning interutility transmission systems, see Public Service Electric & Gas Co., *An Approach for Determining Transfer Capability Objectives,* Electric Power Research Institute, EPRI EL-3425, March 1984.

individual components, or to the requirements and challenges of operating the overall system. Individual transmission line components have specific voltage requirements and limited current-carrying or thermal capability, either of which may constrain their use. System-related constraints involve the complex interactions between individual generators, transmission circuits and their control system, and the needs for maintaining adequate reliability. Table 4-6 summarizes the constraints on power transfers.

Physical laws alone do not dictate the absolute amount of transfer possible. Rather, they indicate a trade-off between level of transfers and reliability. There is no simple power network equivalent of the telephone company's busy signal. For example, higher transfers decrease transmission reserves, increasing the possibility of an outage occurring. As a result, transfer capability depends on both physical characteristics and the reliability standards and procedures used. (Recall that reliability criteria are somewhat subjective and not set on a quantitatively derived balance between the utility's costs of providing reliability and the consumers' benefits of uninterrupted service.)

Determining transfer capability and opportunities for improvements can be a challenging matter of balancing economics, reliability, engineering, and policy, Developing meaningful estimates of transmission capability requires considerable engineering expertise, data, and analytic tools. This challenge arises because capability is not merely the rating of a single line or a few lines. Rather, transmission capability is a function of the strength of the system as a whole, including not only the transmission lines but the generating units as well. For example, spinning reserves of generation located near loads may reduce the amount of transmission capacity from distant generators which must be held in reserve to maintain reliability.

Transmission capability also varies over time, further complicating any assessment of the adequacy, limitations or opportunities for expanding capabilities. It varies as switching operations occur and as demand, generation, and transmission patterns change. Fluctuating patterns of demand, changing availability of generators and transmission lines, even weather, all affect capability.

In some cases, there may be a single binding constraint that would produce a large increase in capability if it could be relieved. More often there are multiple constraints on a single transmission line, or constraints on many lines at the same time so that reliving a single constraint would make practically no difference. For example, in the PJM system, west to east transfers are limited by voltage-related factors 85 percent of the time and thermal limits for the remainder.[18]

Although this section discusses physical constraints, there are also institutional constraints on power transmission. Even with sufficient physical capability, some economically advantageous transfers may not take place. For example, lack of regulatory approval, lack of intercompany agreements or contractual basis, or simply lack of knowledge of economic opportunities may all prove real and significant impediments to full use of transmission capacity.

Constraints on Individual Components

Power is transmitted when the line voltage causes current to flow in the conductors. The amount of power an individual line carries is proportional to the product of the current and the voltage. However, every transmission line is limited in the amount of power it can transmit by constraints on voltage and current. Flows of reactive power limit both the voltage and current capacity.

Thermal/Current Constraints

Current flowing causes conductors to heat up. The amount of heat individual components can tolerate limits the amount of power than can be transmitted. Heating causes the metal conductors to expand and sag. The resulting reduced clearance from the conductor to the ground, towers, and other conductors exacerbates flashover constraints. Excessive heating may also result in a permanent stretching and lead to brittleness and a shorter lifespan. Substation equipment is also subject to thermal limitations. Excessive heat can destroy the materials used in transformers and other terminal equipment.

A thermally overloaded component may reach its critical temperature within seconds, minutes, or hours, depending on its previous temperature, its

[18] Casazza, Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access,* OTA contractor report, March 1988, p. V-4.

Table 4-4-Key Physical Characteristics of Generating Plants

Operating cost
Fuel type and cost
Efficiency
Control ranges
Real power
Reactive power
Startup costs
Ramp rates
Fuel availability
Expected equipment failure-availability
Maintenance requirements and costs
Environmental impacts and emission requirements
Site availability
Location relative to transmission and loads
Construction cost and lead time
Lifetime

SOURCE: Office of Technology Assessment, 1889

Table 4-&Key Transmission Planning Characteristics

Location and capacity of individual lines
Equipment voltage requirements
Capability of VAR support equipment
Transmission losses
Equipment failure rates
Maintenance requirements
Environmental impacts
Rights-of-way and substation site availability
Construction cost
Construction lead time
Lifetime

SOURCE: Office of Technology Assessment, 1989,

physical characteristics, amount of overload, and weather. Therefore it may be able to carry a heavy current for a short time, a lesser current for a longer time, and a still lesser one indefinitely. The latter current is the component's "normal" rating, applicable to normal operation. "Emergency" ratings are currents that can be carried for shorter times on the assumption that the loadings can be relieved by changes in generation dispatch or reductions in loads within the assigned time period.

Thermal ratings are usually established for loadings occurring for different periods of time-10 minutes, 30 minutes, 4 hours, etc. The ratings are typically based on current flows rather than the actual temperatures of transmission line equipment. The actual temperature depends not only on current,

Table 4-6-Transmission Capability Constraints

Physical constraints
Individual line constraints
Thermal/current constraints
Conductor sagging, equipment lifetime
Voltage constraints
Flashover, corona, and terminal equipment requirements
Reactive power flow and voltage
System operating constraints
Distribution of power flows (parallel path and loop flows)
Contingency security
Stability (steady-state and transient)
Institutional constraints
Interutility agreements
Regulatory approval

SOURCE: Office of Technology Assessment, 1988.

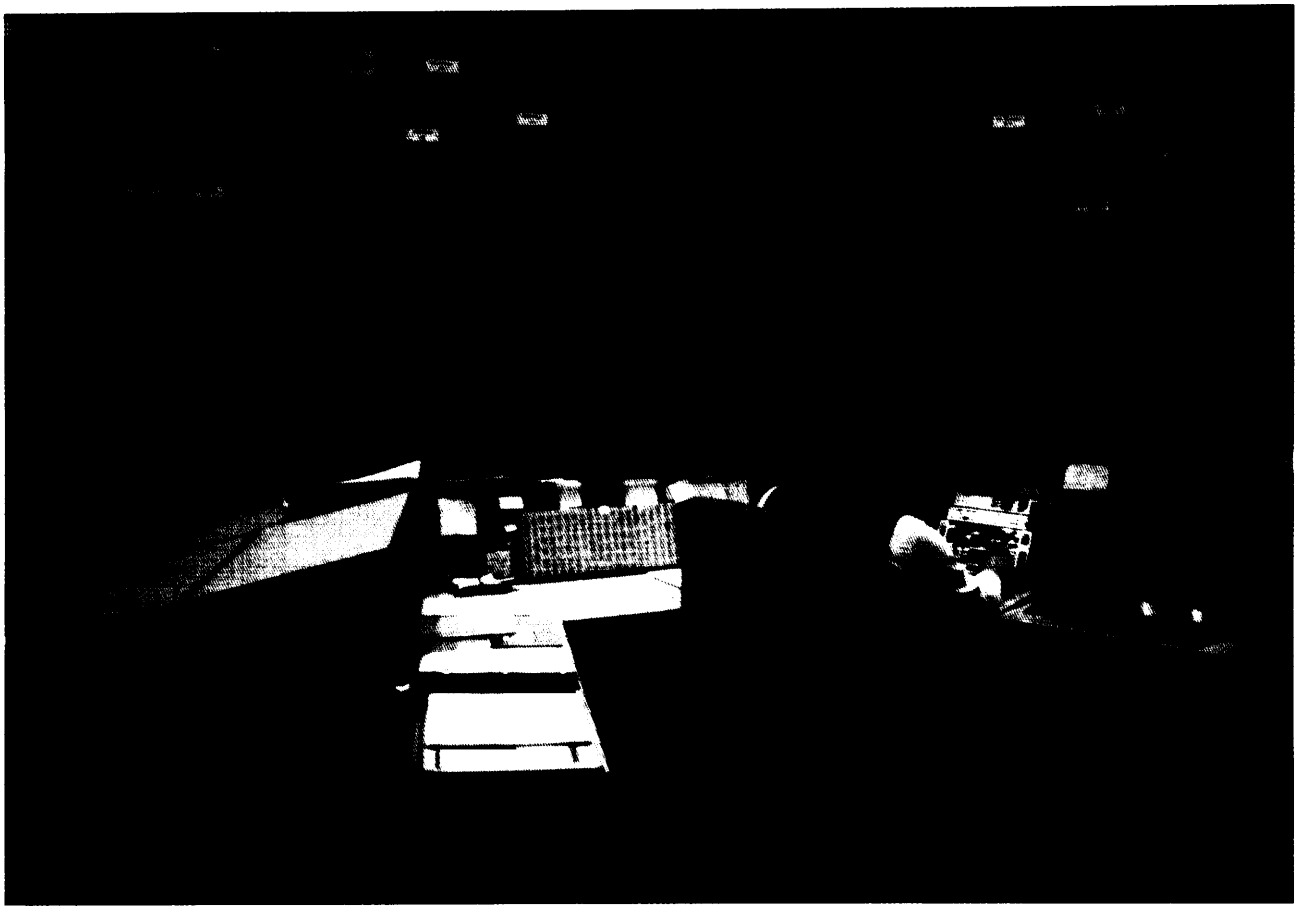
but on ambient weather conditions including temperature, wind speed, and icing. Identical components may have different ratings due to such factors as the expected ambient weather conditions and the reduction in equipment life considered acceptable by the utility.

Voltage Constraints

The design of a transmission line specifies the minimum and maximum operating voltages. Voltages exceeding the maximum may cause electricity to flashover (i.e., arc between a conductor and the ground or the tower), rather than travel along the line. High voltages may also cause corona discharge (i.e., ionized air molecules surrounding the line resulting from high electric fields), creating noise and radio interference. The maximum voltage allowable on a line depends on its height, spacing of the conductors and insulators, and weather (e.g., corona is exacerbated by high humidity, rain, or snow). Excessive voltages may also destroy transformers and other terminal and substation equipment by breaking down their insulation.

Reactive Power Flows and Voltage

As discussed earlier, reactive power flows may cause voltage to rise or drop significantly along transmission lines, particularly long ones. With low real power flows on a transmission line, capacitive reactance may create high voltages along the line, exacerbating high voltage constraints.



Pho credit Casazza Associates

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Similarly, increasing the real power flow on a line also increases the line's demand for reactive power. As the flow of reactive power increases, the voltage along the line drops significantly. If as a result of reactive power flows, voltages fall below the design minimum, transformers will not function and either power cannot be transferred or the voltage of power delivered to customers will be outside the allowable range. Thus, the ability of generators and other VAR control devices to supply reactive power limits the amount of real power which can be transferred. Since the amount of reactive power required by a transmission line increases with line length, reactive power problems typically affect long lines.

System Operating Constraints

Parallel Path Flow: Distribution of Power

The flow of power in a transmission network is dictated by the laws of physics. One of the key laws is that power may flow on all available paths between the generator and the load. This is called *parallel path flow* (which is a slight misnomer, since the lines are not necessarily parallel).

Generally, the amount of power flowing on any path of a network is inversely proportional to that path's impedance. The impedance may bethought of as an "electrical length," which depends on both the actual length and the voltage of the path. (One mile of 500-kV line has approximately one-fifth the impedance of a mile of 230-kV line.) Also, a path's impedance to power flow does not necessarily reflect the transfer capacity of that path.

The distribution of power flows and the inability to control the flows has two important implications for determining transmission system capability. First, *the transmission capacity of a network is not the sum of the power that could be carried on each line alone. Rather, the capacity is constrained by the weakest link. The* amount of power that can be transferred from one area to another by a transmission system is the smallest power transfer at which one of the components reaches a thermal or voltage limit. (See box 4-C.)

Second, *the capability of transferring power from any generator to any loud on the system depends on the other transfers occurring simultaneously. The* power flow from a generator to a load divides onto each pathway to some extent. Even indirect or distant lines may receive some of the flow and thus have part of their capacity used up. As a result, the capacity remaining for additional transfers between other generators and loads depends on the other transfers since they essentially share the same transmission paths.

Parallel path flows and resulting transmission problems can occur both within a single utility and between interconnected utilities exchanging power. Parallel path flows crossing the boundaries of utilities along paths not contracted for, or scheduled, are called *loop flows. (See* box 4-D.) In interconnected systems, such as those in the United States, loop flows are common.

System Stability

In an electrical generating network all generators rotate in unison, or synchronism, at the system frequency of 60 Hz. The ability to maintain synchronism is called stability. Transmission capability may be limited by instability. Normally, a disturbance increasing or decreasing the speed of one generator will cause small changes in the unit's power output, tending to bring that generator back to the common speed of the system. Instability is a condition in which this stabilizing process does not occur, and some generators speed up with respect to others, possibly causing the system to fall apart.

Two types of stability can be classified according to the magnitude of the disturbance: steady state and transient.[19] ***steady state*** stability refers to the ability of the system to withstand small changes in loads. Transient stability refers to the ability to withstand large disturbances, such as the failure of a transmission line or generating unit. System engineers use complex computer programs representing the generators, controls, loads, and the network itself to examine which operating conditions (e.g., power flows on the transmission system) are stable and which are not.

Contingency Security

A major disturbance such as the failure of a generating unit or transmission component causes changes in real and reactive power flows and voltages around the system. As discussed earlier, the n-1 contingency security standard for reliability requires that a system continue functioning without cascading failures caused by thermal overloads, or excessive voltage drops or sags, or instability if any single component should fail without notice. Voltage control devices and generating units are set to respond to a contingency to restore the frequency, voltages, and power flows to acceptable levels. Because of the possibility of a major disturbance, the transmission system's capability of carrying power is limited not only by the actual flows but by the flows that would exist if a given contingency should occur. (See box 4-C.)

The standard approach to avoid such cascading failures is to operate in a *defensive or preventive mode.* In this mode, generation is dispatched and flows are maintained so that sufficient generation and transmission capacity is held in reserve to ensure that the resulting redistribution of power would remain within emergency ratings following the most severe single contingency.

While the defensive mode is essential for reliability, it may require operating more costly generating units when lower cost units are available. There is an alternative to defensive scheduling of generation and transmission, that of developing

[19] Institute of Electrical and Electronics Engineers (IEEE) Committee Report, "Proposed Terms and Definitions for Power System Stability," *IEEE Transactions on Power Systems, vol.* PAS-101, No. 7, February 1986.

Box 4-C—Example of Transmission Constraints

The transmission capability between two points in a system may be limited by individual component constraints or by network constraints. Individual line constraints may be exacerbated by parallel path flows in the network. This highly simplified example shows some of the different constraints and their impact on overall transmission capability.

Component Constraints

Consider the very simple transmission network illustrated in figure 4-4. Three parallel transmission lines connecting a generator to a load. Each line has a capacity of 100 MW, above which it is constrained both thermally and by voltage. That is, increasing power flows above 100 MW by increasing current would cause overheating and sagging of the line. It would also increase reactive power demand, reducing the voltage at the receiving end below acceptable levels. Increasing power flows by increasing voltage would cause flashovers, corona discharge, or possibly destroy terminal equipment, If all three lines could be fully utilized, the system would have the ability to transfer 300 MW.

Parallel Path Flows

Because of different path lengths, the power transmitted may divide unequally on the three lines. Assume that the division is in the ratios of 10:9:8. Because of the uneven division, when Line A carries its rated power of 100 MW, Lines B and C carry only 90 and 80 MW respectively. Any attempt to transmit more power would increase the loading on all three lines and overload Line A. Thus, due to the impact of parallel path flows, the total capacity is only 270 MW.

Contingency Security Constraints

Using the defensive mode to meet the "n-1" contingency security requirement reduces the transmission limit even more. If Line B were to suddenly fail, perhaps after a lightning strike, Lines A and C would receive the additional flow and be loaded to 150 MW and 120 MW respectively. To prevent the possibility of an overload, the allowable power transfer is only 180 MW. Then the normal loadings are limited to only 67, 60, and 53 MW respectively, and the emergency loadings do not exceed the rating of 100 MW. The three 1OO-MW lines form a system capable of safely carrying only 180 MW, or 60 percent of their total individual ratings.

Transient stability studies of this system may indicate that the two generators will lose synchronous operation after a disturbance such as the line loss, even though no individual components are overloaded. That is, one generator may slow down while the other accelerates, as both respond to the new voltages and power flows. If this is the case, stability concerns may require further limiting transfers.

SOURCE: Office of Technology Assessment, adapted from Casazza-Schultz & Associates, Inc., Case *Studies on Increasing Transmission Access,* OTA contractor report, March 1988.

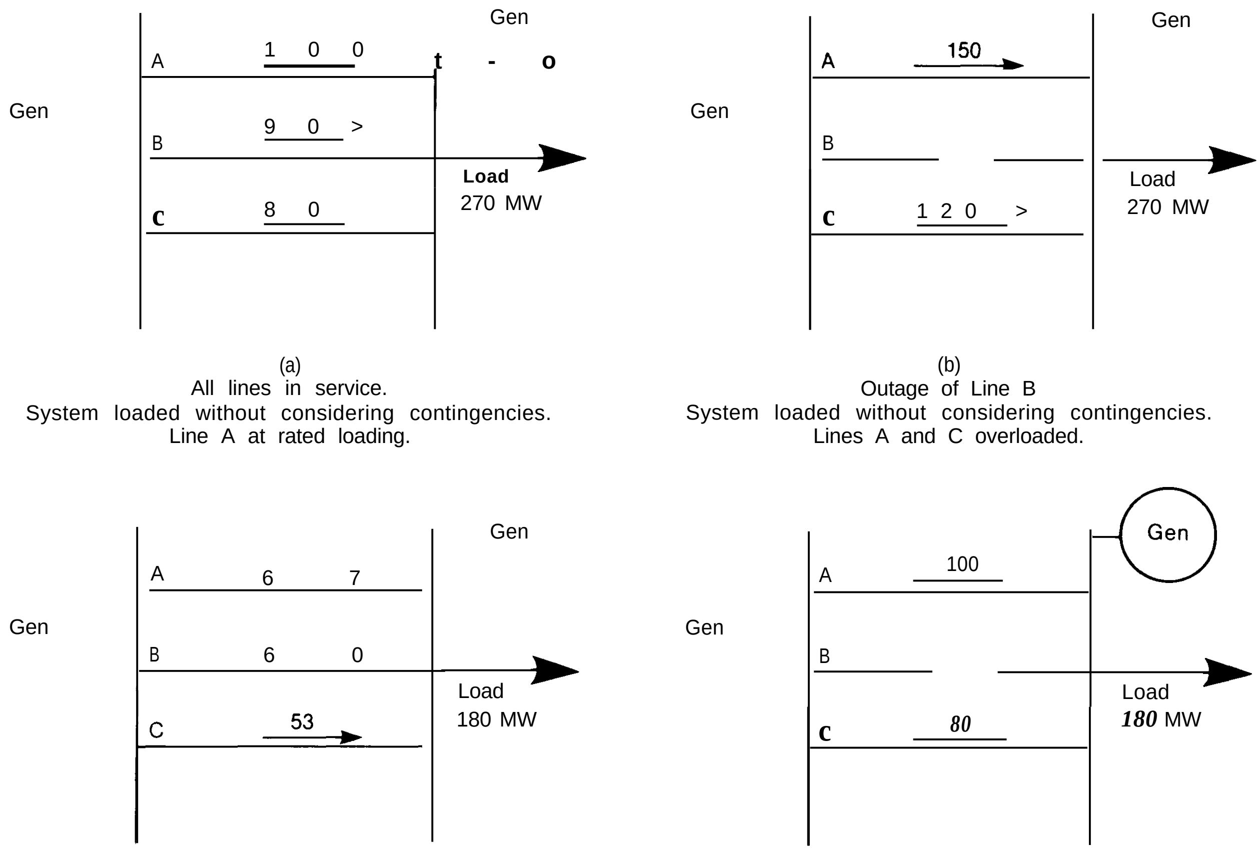
special protection systems for responding rapidly enough to prevent cascading failures after a disturbance occurs. Such a mode of action is referred to as *corrective or remedial action.* Remedial action might involve measures including tripping (or rapidly disconnecting) a remote generator while rapidly increasing the output of a nearby generator when a specific contingency occurs. It is typically used when the preventive mode of operation would entail a heavy economic penalty.

According to the North American Electric Reliability Council (NERC), corrective action systems are being considered more frequently as an alternative to defensive generation scheduling.[20] NERC notes that widespread application of these more complex schemes may affect future power system reliability since system security becomes dependent upon the correct functioning of these special protective systems. To provide the same reliability as the defensive mode, special protection schemes must either be highly reliable or have built-in redundancy.

In practice, limits caused by contingency security are challenging to analyze. Circuit configurations are far more complex than the example of box 4-C,

[20] North American Electric Reliability Council, *1987 Reliability Assessment—The Future of Bulk Electric System Reliability in North America,*)987-/996 (Princeton, NJ: October 1987).

Figure 4-4-Transmission System Limitations (all lines rate 100 MW)



(a)
All lines in service.
System loaded without considering contingencies.
Line A at rated loading.

(b)
Outage of Line B
System loaded without considering contingencies.
Lines A and C overloaded.

(c)
All lines in.
System loaded to “n-1 contingency limit”

(d)
Outage of Line B
System was loaded to “n-1 contingency limit” before Line B tripped.
Line A at limit. No overloads.

SOURCE Casazza, Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access,* OTA contractor report, March 1988.

and the redistribution of power flows after some equipment failure is complicated. Also, both real and reactive power flows and their impact on voltage and thermal limits must be considered. Moreover, following a disturbance, the transition to the new equilibrium state is not instantaneous. Rather, the change occurs over time as generating units and voltage control devices react and interact with each other. Thus, stability analyses must examine not only whether the new state following a disturbance is stable, but also whether transition to a new stable state will occur.

Prospects for Increasing Capability

Assuming that an increase in transmission capability is desired, what can be done? There are possibilities for mitigating all types of constraints. Options for upgrading both the transmission system and generators may be useful. Options include:

1, increasing the thermal or voltage capacity of an individual existing line,
2. improving the control of reactive power and voltages on a network,

Box 4-D--Loop Flows in the Western System Coordinating Council (WSCC)

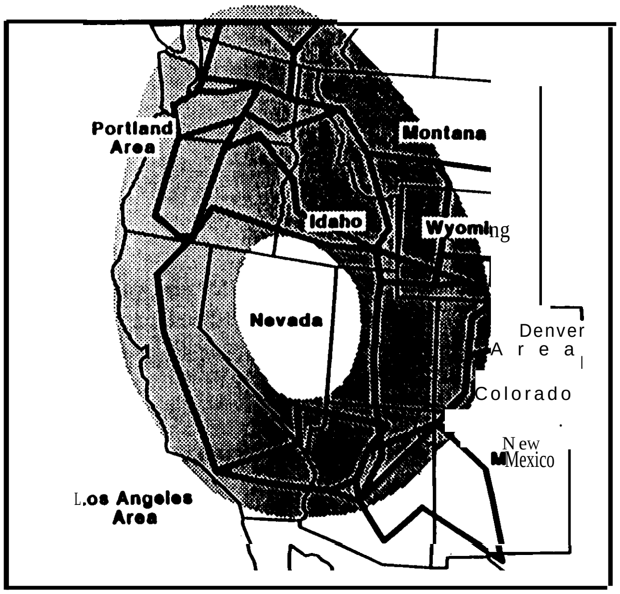
Loop flows, the unscheduled use of another utility's transmission resulting from parallel path flows, is common in the WSCC as in other parts of the United States. The WSCC transmission system has the general shape of an elongated doughnut including a western section of lines joining Oregon and California; an eastern section running generally from Montana to Arizona; a section in the Northwest; and a section from southern California to Arizona. Figure 4-5 shows a simplified view of the WSCC doughnut.

Because of the shape of the transmission system and the physical laws of electricity, whenever power is sent from one part of the doughnut to another, the flow is split two ways; some goes clockwise, and some counterclockwise. For example, if 1,000 MW of power is sent from the Montana-Wyoming area to the Pacific Northwest, only 580 MW of this power flows along the relatively direct counter-clockwise path, as seen in the figure below; the remaining 420 MW flows clockwise through California and north through the western lines. The flows due to simultaneous transactions carried on at the time are superimposed on each other depending on their amount and direction. For example, a sale from the Northwest to California would reduce or reverse the flow between the Northwest and Montana-Wyoming, and increase the flow from Montana-Wyoming to California on the eastern lines.

If the transaction from Montana-Wyoming to the Northwest used a scheduled or contract path directly joining the two areas and not including California, the 420 MW flow not using that path is a clockwise loop flow. WSCC has pursued use of flow control devices called phase shifting transformers to reduce loop flows.

SOURCE: Casazza-Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report, March 1988.

Figure 4-5--Western Interconnected System



SOURCE: Casazza-Schultz & Associates, Inc., *Case Studies on Increasing Transmission Access*, OTA contractor report March 1988.

3. improving the control of real power flows on a network,
4. decreasing the response time of generators and transmission line switching, and
5. adding new lines.

Table 4-7 shows how these options relate to the types of system limitations.

The costs of increasing transmission capability are site-specific, depending on a host of factors such as terrain, system configuration, type and age of equipment being upgraded, etc. Often, a transmission line or generator being upgraded must be temporarily taken out of service. Lost use of the equipment creates a highly site-specific cost, particularly significant in cases where a line being upgraded is in heavy use. As a result, generalizing about cost and performance is difficult.

Meaningful estimates of the benefits of options to increase transfer capability are even more difficult to develop. There are several reasons. First, most changes will affect not only transfer capability but the system operating economics and system reliability as well. Developing a meaningful combined measure of performance that trades off between these factors has proven elusive. Second, the impact of any measure of system transfer capability, operating economics, and reliability is highly site-specific. The impact of a new transmission circuit in a remote part of Nevada and an identical circuit parallel to an

Table 4-7-Technologies To Increase Transfer Capability

Remedies to individual line constraints
Voltage uprating
Tower extensions
Upgrading insulators
Upgrading terminal equipment (circuit breakers, relays, transformers)
Current uprating
Dynamic conductor rating
Sag assessment and monitoring
Restringing (live-line restringing)
Changing operating standards
Tower design and new lines
Conversion to multiple circuit towers
High-voltage direct current lines
Remedies to steady state system operating constraints
Control of load division
Phase angle regulators
Series reactance and capacitance
System reconfiguration
HVDC control features
Redispatch of generation
Reactive power management techniques
Shunt or series capacitors
Shunt reactors
Static VAR compensators
Synchronous condensers
Generators as VAR sources
Remedies to contingency security and stability constraints
/reproving generation response controls
Generator tripping and fast runback
Fast valving
Braking resistors and load switching
Advanced excitation systems and stabilizers
Transient excitation boost
Improving transmission response controls
High-speed reclosing and reducing clearing time
Rapid adjustment of network impedance
Fast acting phase angle regulators
Sectionalizing (adding switching stations)

SOURCE: Adapted from Power Technologies, "Technical Background and Considerations in Proposed Wheeling, Transmission Access, and Non-Utility Generation,' contractor report prepared for the Office of Technology Assessment, March 1988, p. 6-2.

existing line in the Northeast are considerably different. Also, the impacts vary over time, as loads change, and as available resources and their costs change.

The following is a summary of some of the approaches to increasing transfer capability. For a more comprehensive, technical description of solutions to increased transfer capability the reader is referred to *Technical Limits to Transmission System Operation,* published by the Electric Power Research Institute.[21]

Increasing the Capacity of an Existing Line

Increasing Voltage

Since the acceptable voltage range for operation of transmission circuits without flashovers is determined primarily by the line's equipment and design, the opportunities are limited to changing equipment. Transmission towers can be extended and insulators upgraded to increase the spacing between the conductors, towers, and ground. Terminal equipment such as switches, circuit breakers, meters, and transformers will also need to be upgraded to the higher voltage ratings.

Increasing Current Ratings

One method to uprate the current carrying capacity of a line is to simply increase the allowed temperature rise, and thereby increase the amount of current flow allowed. This method has a very low initial cost. However, there may be some reduction in equipment lifetime.[22]

A related technique is to use *dynamic line ratings.* Normally, a line's current ratings are based on imprecise and conservatively forecast estimates of ambient weather conditions. Using dynamic line rating, the actual ambient weather and the temperature and sag of the conductor are measured, permitting the line to operate closer to its physical limits on cool or windy days. Dynamic line rating adds some increased operational complexity and increases the variability of transfer capability over time.

Resagging a line to raise it higher off the ground may also allow increased current flows if the line is constrained by excessive sagging. This has been done in some cases while the line is still in service. Another option is restringing-installing a larger conductor with higher current ratings. This may

[21] Power Technologies, Inc., *Technical Limits* t. *Transmission System Operation,* EPRI EL-5859, June 1981?.

[22] *IEEE Standard for Calculation of Bare Overhead Conductor Temperature and Ampacity Under Steady-State Conditions.* ANSI/IEEE Standard 738-1986, 1986.

require reinforcement of the existing towers but costs considerably less than adding a new line.

Tower and Circuit Reconfiguration

Voltage and/or current limits may also be extended by more extensive changes in line circuit and tower design. If tower strength permits, a single wire line may be replaced by a bundle of two to four wires, raising both thermal and corona limits. In addition to restringing circuits already in place, it may be possible to string another separate circuit, Original towers may already have space for new circuits in anticipation of future need. A new possibility under investigation is either to restring an old AC line as a new HVDC line, or to add a new HVDC circuit in combination with an existing AC circuit as space permits.

Controlling Real Power Flows

As explained above, network transfer capability is limited by the most constrained line in the system, so any method which can control or alter flow in the network may have major benefits. There are number of methods which can be used to control network flow, but this is done by changing the network characteristics in different places, rather than by changing the rules of network flow.

The first and foremost technique for controlling network flow is off-economic dispatch of generating units. By generating power at particular network locations, rather than in economic order, network flow can be kept with reliability and capacity limits.

A second practical, inexpensive, and common method is to alter the network itself by disconnecting one end of a constraining (typically lower voltage) line. The line then carries only the customer load it serves. This method may also be used on one of two parallel lines under low load conditions, so that increased loading on the remaining line is better matched to the VAR compensation present. In both cases, the benefit is purchased at the cost of lower reliability, as fewer paths between generation and loads remain.

Phase shifting transformers (also called phase angle regulators) change the phase angle between input and output by advancing or retarding the relative time at which the input and output sine wave voltage peaks occur. By doing so these devices act as a valve which can increase or decrease the flow of power on a line. Phase shifting transformers have not been widely used due to past problems with reliability. They also have the undesirable side effects of increasing reactive power losses. There is some hope that future developments in high-power electronics will produce devices that can be used with phase shifting transformers to control individual line flow (discussed below).

A technique called Rapid Adjustment of Network Impedance (RANI) can be used to continuously vary VAR compensation to maximize power flow on a single line. It can also be used to vary the impedances on one or more lines in such away as to control power flow on the network. Because this control is achieved by varying line impedance, there is the possibility that it will be paid for in increased line losses. The cost of such line losses must be balanced against improved reliability, reduced need for new power lines, and other benefits.[23]

High-voltage direct current (HVDC) power lines are used for high-power, long distance lines and as asynchronous connections between the three main interconnected regions of the United States. Through application of high-power thyristors used to convert AC power to DC and back again, the voltage and hence the power transfer of the DC line can be directly controlled, possibly enhancing stability as well. While it is currently uneconomic to use DC lines for such power flow control, research continues on multiterminal DC lines and improving the cost and capacity of high-power semiconductors. HVDC appears to be the single most powerful method of direct flow control in the battery of options and with economic feasibility could have a major impact on the industry.

[23] The Bonneville power Administration is experimenting with RANI, with a preliminary study showing it to compare favorably with mechanically switched shunt capacitors, static VAR compensators, and mechanically switched series capacitors on the Pacific AC Intertie in providing transient support and damping and post-disturbance support and stability. In one configuration. loop flow was reduced 43 percent (348 MW) at the cost of 68 MW incremental losses. (Personal communication with Mr. Dean Perry of BPA, July 1988).

Controlling Reactive Power and Voltage

Increasing the availability and control of VAR supplies on the system is one approach to alleviating voltage-related transmission limits.[24] Generators are one common source of VARs as well as real power. Capacitors may be installed at various points to increase the available supply of VARs. The capacitors can be designed to be switched in and out of operation, allowing operators to control VAR supplies. Synchronous condensers and static VAR compensators may also be installed on transmission lines to provide a controllable source of VARs. Inductors may be connected in shunt with the line in specific instances. Series connection is rare and used to control excess current in short circuit conditions. Another technique typically used to control VAR flows is to control the VAR output of generators, just as real power is controlled.

Increasingly, methods are being developed for operation and control systems to use computer load flow models (called optimal power flow models) to simultaneously dispatch both VARs and real power. It is anticipated that the future will see more applications of these methods, The cost of implementation will include metering and communication and control equipment as well as new software.

Stability Response

A utility can increase its transfer capability by shifting its reliability policy from the preventative mode of operation to the remedial mode. There are numerous special protection schemes being developed and applied. Generation response options generally increase the ramp rate at which a generator can increase or decrease its output or temporarily increase its peak output. These options may increase maintenance costs by increasing operating stresses.

Generator "tripping," "fast runback," and "fast valving" systems are generator control schemes designed to rapidly reduce power fed into the grid while continuing to keep the unit on line and available, Increased output from generators can be obtained by temporarily turning off auxiliary plant equipment at the generating stations. A 10-percent increase in output may be temporarily obtained using these measures. However, operating power plants in this way may reduce equipment life or increase the risk of failure.

These methods have been used in specific cases but have not been widely applied to date. They require careful study and application if they are to achieve the same level of system reliability as achieved by the defensive scheduling techniques.

Future Trends

A wide variety of techniques for increasing transfer capability are in use and under development in the United States. There are some developments which may have significant long-term effects on system operation and transfer capability. These include developments in high-power semiconductors; ongoing improvements in computing and data processing capabilities; and, in the very long term, possibly even superconductivity.

In general, developments in these areas will have gradual but increasing impacts. For example, high-power semiconductors are already leading to fast, nonmechanical switching of VAR control devices. Further developments will lead to improved reliability and speed for phase shifting transformers and other devices, before direct switching of high-voltage alternating current (HVAC) lines becomes possible.

High-Power Semiconductors

With few exceptions, present-day power systems use mechanical control devices. Mechanical circuit breakers, relays, switches, tap changing transformers, and generator controls use moving contacts to close or open circuits, and are therefore limited in the speed and number of times they can operate. These limitations mean that power systems are neither as responsive nor as reliable as may often be desired.

Developments in high-power semiconductors to allow electronic rather than mechanical control promise to improve the performance of the power system in significant and pervasive ways. This is not a sudden revolution, but a continuing trend that has already lead to static VAR compensation and HVDC transmission lines. However, recent research has

[24]See, for example, Scientific System, Inc., *Optimization of Reactive Volt- Ampere (VAR) Sources in System Planning*, EPRI EL-3729, Electric Power Research Institute, November 1984; and University of Washington, *Reactive Power Management Device Assessment,* EPRI AP-5210, Electric Power Research Institute, August 1987.

dramatically expanded the prospects for a range of future uses.[25]

Controlling Power Flow

There are several possible applications of high-power semiconductors to the general area of controlling power flows.[26] As described above, there are many means of relaxing power transfer constraints, and several of them have the opportunity to be significantly improved by the use of high-power semiconductors. Static VAR Compensations and Rapid Adjustment of Network Impedance (RANI) are both early applications of high-power semiconductors (thyristors). Both methods rapidly and continuously vary the amount of shunt or series reactance present to control the total line impedance. Higher power semiconductors will have applications to phase-shifting transformers and variable voltage tap-changing transformers.

Use of high-power semiconductors as switches, or resettable fuses, to directly reconfigure the actual network will require very high voltage and current capabilities. Switches that can handle such high voltages and currents economically have not yet been developed, but the prospect is within sight. The speed and control of switches that can turn on and off every cycle (or more often) without wearing out will make remedial reliability methods more practical and economic.

High-power semiconductors are currently used on HVDC power lines to convert AC power to HVDC and back again. The power thyristors used in this conversion are sufficiently expensive that HVDC power lines are only practical for lines which are long enough to bear the high terminal cost or as interconnections between asynchronous systems. Lower cost and higher capacity semiconductors will make shorter DC lines economically practicable and allow multiterminal HVDC lines, instead of the two terminal lines now used. Because the conversion voltages at both ends of a line can be controlled, HVDC transmission allow essentially complete control of network flow.

Power Control of New Energy Sources and Storage

In addition to increasing network transfer capability and reliability, high-power semiconductors will play a crucial role in power conversion and conditioning for new power sources and energy storage systems. Energy sources such as photovoltaics and fuel cells produce relatively low voltage DC power. It is necessary to convert this power to AC in order to connect the generating unit to the grid. Wind power plants already produce AC power, but the mechanical governors needed to regulate frequency are liable to stress, reduce reliability, and limit the maximum power available from the wind. Solid state power conversion can be used to let the wind turbine generate as much power as possible, convert the variable frequency power to 60 Hz AC, and also supply VARs to compensate for the natural inductance of these generators. In addition to generation, various proposed energy storage methods require conversion of AC to DC power, and back again. Whether as basic as batteries or as esoteric as superconducting magnetic energy storage, higher power semiconductors will play a key role in making the necessary energy conversion reliable and efficient.

One key to increasing semiconductor power capability is the development of high-purity silicon devices which can handle large currents and voltage with losses low enough that device temperature is reasonably limited. One such device being developed is the metal oxide semiconductor controlled thyristor (MOS-CT). These devices are light fired, or optically triggered, by a laser diode either directly or via fiber optics. Unlike conventional thyristors, these devices can be turned off as well as turned on during each half cycle. More importantly, these devices can combine a microprwessor on the same chip as the power semiconductor to produce integral intelligent control of the high-power switch. The thyristors may be stacked in parallel or series to increase current and voltage and this stacking may be done either on a single chip or by stacking chips together.

[25] Steitz & Associates, *Materials and Devices for Power Electronic Applications*, EPRI AP/EM/EL-5470, Electric Power Research Institute, March 1988.

[26] N.G. Hingorani, "High Power Electronics and Flexible AC Transmission System," *IEEE Power Engineering Review*, July 1988, pp. 3-4.

Development of high-power semiconductors is currently underway as a joint effort between industry and government. The Department of Defense is interested in high-power switching required for Strategic Defense Initiative (SDI) applications, and the National Aeronautics and Space Administration (NASA) is also interested in civilian space-drive applications. In October 1987, EPRI opened the Power Electronics Applications Center in Knoxville, Tennessee. This center and a series of yearly conferences are intended to promote industrial and consumer end-use applications of power electronics, rather than basic research. This effort reflects the belief that recent power electronics developments have created opportunities and that applications have lagged their potential.

Research is being conducted primarily by General Electric with some work also being performed by Westinghouse. The work is being funded by the Army (under SDI), Navy, Air Force, NASA, and EPRI. Current funding is about $3.5 million per year, with about $2.5 million being spent upon hardware/device development and about $1 million (from DARPA) being spent on materials development. Total government spending is estimated to total 10 to 40 million dollars, excluding industry investment.

Single semiconductor devices rated up 20 kV and a few thousand amps are envisioned within the next 10 to 30 years which will meet utility needs with low losses, low cost, and fast switching capabilities. Such capabilities make it likely that delivered power will flow through high-power semiconductors several times before reaching the customer.

Improving Computer Capabilities

Continuing trends in data processing and computing capabilities have widespread applications in power system operations and planning.[27] Expert systems and artificial intelligence continue the trend towards increasing computer applications in the utility industry and are properly a subset of a wide array of advancing modeling and computer analysis capabilities.[28]

Expert systems essentially codify a subject or system of knowledge that is too large or esoteric for the end user, into software form. The codified rules then guide the user interactively by requesting data and making suggestions. Some of the varied applications for improved computing capabilities include the following.

System Engineering and Planning

System planners use many specialized computer applications for such diverse activities as:

- forecasting and modeling loads,
- selecting generation expansion plans,
- selecting transmission capacity expansion plans,
- examining reliability of systems,
- investigating system stability, and
- real and reactive power flows resulting from systems changes.

Many of these applications are computationally challenging and are continuing to benefit from the expanding abilities of both computer hardware and software.

Control Center Operations

As in system planning, many specialized computer applications are used in control centers. Faster and more powerful hardware and software allow improved monitoring, analysis, and modeling of system conditions as they change. Areas of application include:

- real-time load flow models allowing optimization of VAR dispatch and optimization of power transfers,
- improved monitoring of thermal conditions and voltages on transmission lines allowing dynamic line ratings,
- improved response to system emergencies, and
- real-time assessment of contingency security.

Transmission and Distribution Automation

The current transmission and distribution system is largely mechanically controlled and operation is confined primarily to generation dispatch and emer-

[27] See for example, "Special Issue on Computers in Power System operations,'" *Proceedings of the IEEE,* December 1987; or Carlsen & Fink Associates, Inc., *Integrated Power System Analysis Package · Scoping Study*, EPRI EL-4632 vols. 1 and 11, Electric Power Research Institute, July 1986.

[28] University of Washington, *Development of Expert Systems as On-Line Power System Operational Aids,* EPRI *EL-5635,* Electric power Research Institute, February 1988. Carnegie-Mellon University, *Artificial Intelligence Technologies for Power System Operations*, EPRI EL-4323, Electric Power Research Institute, January 1986.

gency response. Development of more flexible AC transmission controls, increased dependence on remedial reliability responses, and distribution automation (including load shedding control) are trends which will complicate operation of the transmission and distribution system. These trends, which should bring improved reliability and economy, make use of the advances in communication and data processing capabilities.

Power Plant Diagnostics and Monitoring

Advances in power plant diagnostics and control systems allow more reliable and efficient operation at the price of complexity. Expert systems can assist the operator in a range of ways from finding problems before component failure, to helping determine ramp rates and timing that will optimize the trade-off between heat rate and plant life.

Operator Training and Simulation

In addition to helping run a generating plant, expert systems can also be used for initial and ongoing training of operating personnel. Such systems can be useful in practicing responses to extreme situations which rarely occur, especially in nuclear plants. Nuclear plants typically have a simulator operating room for such purposes, but expert systems can assist in organizing, recognizing, and responding to data instead of just presenting a scenario.

Superconductivity

Superconductors will have a number of obvious and important possible applications in the utility industry when further development makes them practical. These applications include superconducting generators, transmission lines, magnetic energy storage, and large inductors.

These possible uses have been recognized for a long time and have been researched to a limited extent using older, conventional low-temperature metal superconductors. The recent discovery of ceramics which superconduct above the temperature of liquid nitrogen (77° K) raises the hope of much reduced costs and wider applications. The rate and extent of superconductor applications depends upon how fast and how far it is possible to push three interrelated limits to superconductivity: critical temperature, magnetic field, and current density. The critical temperature is the best known limit and determines the extent of thermal losses (which would be important in applications such as transmission lines). The current density limit is also important for power applications, since it is key in determining size and cost. Cost limitations will probably be based primarily upon fabrication costs and operating costs.

The most likely actual early use appears to be in energy storage.[29] Economic storage of electricity using superconducting magnets would be revolutionary indeed. The structure and operation of the utility business is built on the fact that electricity cannot be stored. Storage options to date include pumped hydro, compressed air storage, and batteries, but are site limited, inefficient, and/or expensive. Energy storage would allow supplying electricity at a relatively flat, constant rate to meet the changing daily load curve, which would in turn allow use of efficient, base-load plants only. Reliability, system control, and the use of new energy sources (such as photovoltaics) would all benefit enormously.[30]

The difficulties will include cost, refrigeration, and enormous magnetic stress on brittle ceramic superconductors. On a smaller scale, energy storage may be used to improve system stability and reliability.

Another possible application is in generators, where use of superconductivity would produce higher magnetic fields, smaller size, and lower losses. Because of the high efficiencies of conventional generators (greater than 98 percent), gains would be relatively small. Preliminary designs and testing of prototypes have already been made for such generators, using lower temperature metal superconductors.[31]

[29] U.S. Congress, Office of Technology Assessment, *Commercializing High Temperature Superconductivity*, OTA-ITE-388 (Washington, DC: U.S. Government Printing Office, June 1988), p. 161.

[30] For a discussion of the more general benefits of storage, see Electric Power Consulting, Inc. *DYNASTORE—A Computer Model for Quantifying Dynamic Energy Storage Benefits*, EPRI AP-5550, Electric Power Research Institute, December 1987.

[31] U.S. Congress, Office of Technology Assessment, op. cit., footnote 29.

Transmission lines are a possible later use, but not necessarily as attractive as they might first appear. Although the line would have no resistance, this would have to be balanced against cooling losses, total cable and burial costs v. an overhead line, and (presumably) reduced right-of-way requirements. More importantly, we have already seen that pure resistance losses are not the constraining limits to power transfer, particularly for medium and long lines. Superconducting cables will not relax synchronous stability or voltage support constraints. HVDC circuits would benefit much more from superconducting lines but AC/DC conversion equipment costs will still limit use to long lines until the price of high power semiconductors drops. In either case transmission losses typically total in the neighborhood of 1 to 3 percent (up to 6 percent for systems with long lines), so any improvements will not be revolutionary. Reduced siting and environmental impact of buried superconducting lines may be major forces even if purely economic benefits are marginal.

Some utility applications of superconductivity have already been designed and tested. These include:

- A 1982 test of superconducting transmission cable proved a 2,000 MW capacity for a 16 inch, liquid helium cooled test cable. This test was performed by Brookhaven National Laboratory in conjunction with EPRI.
- A superconducting magnet installed and tested by the Bonneville Power Administration for use in controlling transmission line fluctuations at its Tacoma substation. This reliability application of magnetic energy storage is likely to precede application of large-scale energy storage for flattening daily load curves.