Electric Utility Industry Structure, Regulation, and Operations

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Electric utilities occupy a unique place in the U.S. economy. Their activities touch virtually everyone. Their regulated status as public utilities imposes special responsibilities in return for assurances of the opportunity to recover their costs, and for investor-owned utilities, to earn a reasonable return on their investments. Maintaining the reliable operation of the Nation electric power systems requires a high degree of cooperation and coordination among sometimes competing utilities and adherence to stringent performance standards. Yet, there is great diversity in the structure and organization of the industry. The recent growth of unregulated, independent power producers and pressures from consumers and regulators for greater utility investment in electricity-saving technologies pose new challenges for utility operations and the regulatory compact.

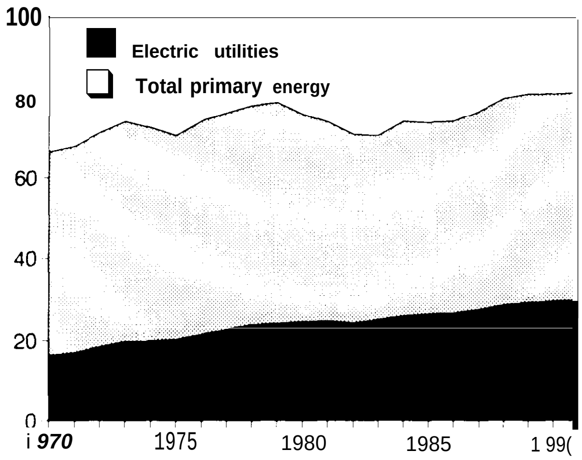
This chapter provides an overview of the electric utilities sector. It begins with a look at utility energy use, financial characteristics, environmental considerations, and an overview of industry structure. Next, it gives a brief introduction to State and Federal regulation of electric utilities. It concludes with an overview of utility system operations.

ELECTRIC UTILITIES IN THE US. ECONOMY

Energy Use

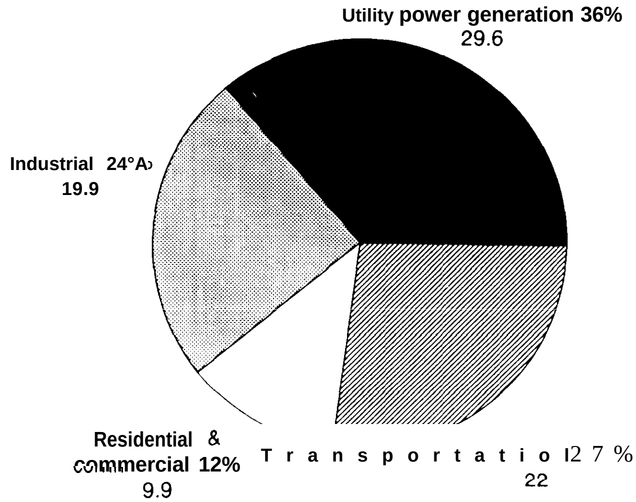
Electric utilities are among the Nation's biggest energy users and energy producers. Utility power generation accounts for 36 percent of total primary energy use in the United States or 29.6

Figure 3-1—U.S. Primary Energy Use, 1970-91 (quadrillion Btus)



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy information Administration, Annual Energy *Review 1991,* DOE/EIA-0384 (91) (Washington DC: U.S. Government Printing Office, June 1992).

Figure 3-2—U.S. Primary Energy Consumption by Sector, 1990 (quadrillion Btus)



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1990,* DO/EIA-0384 (90) (Washington, DC: U.S. Government Printing Office, May 1991), p. 5.

quads in 1990.[1] (See figures 3-1 and 3-2.) Energy use for electric power generation as a share of the Nation's total energy consumption has been growing-faster than growth in demand for other energy sources—and that trend is projected to continue.

Utility fuel demand strongly influences the growth and structure of primary energy markets. In 1990 energy inputs for providing electricity accounts for virtually all nuclear power, 86 percent of coal use, 15 percent of natural gas, 3 percent of oil consumption, and over 40 percent of renewable energy production.[2]

Of the 29.6 quads of energy input to electric utilities to produce power, only 9.3 quads were delivered to retail customers as electricity.[3] On average only 31 percent of the primary energy input to electric power generation and transmission is available/delivered to meet customer needs. The rest is lost to inefficiencies in power generation processes-heat loss, incomplete combustion, and transformer and line losses in transmission and distribution. Thus, even modest gains in the efficiency of electricity production and delivery systems could make significant contributions to improving overall energy efficiency. And the impacts of demand-side electricity savings are magnified when they are translated

[1] U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1991,* DOE/EIA-0384(91) *(Washington DC:* U.S. Government Printing Office, July 1992) p. 15, table 5, hereinafter DOE, *Annual Energy Review 1991.* Because electricity can be considered an energy carrier, the means by which the energy content of fuels, falling water, sunlight, etc. is captured and converted to electricity that is then used to power other activities or energy services, electric utilities are at times categorized as energy producers rather than energy consumers. As a result, electric utilities would be omitted from profiles of energy consumera, and the primary energy inputs used by them to generate electricity is allocated proportionately to end-use sectors.

[2] DOE, *Annual Energy Review 1991,* supra note 1, various tables.

[3] Ibid.

Tables 3-1—Selected Utility Statistics by Sector, 1990

Sales to ultimate consumers (billion kWh)	2,713
Residential	924
Commercial	751
Industrial	946
Other	92
Revenue from sales to ultimate consumers ($billion)	178
Residential	72
Commercial	55
Industrial	45
Other*	6
Average revenue/kWh (cents)	6.6
Residential	7.8
Commercial	7.3
Industrial	4.7
Other	6.4
Emissions (million short tons)[b]	
Sulfur dioxide (SO_2)	16.5
Nitrogen oxides (NO_x)	7.1
Carbon dioxide (CO_2)	1,976.3

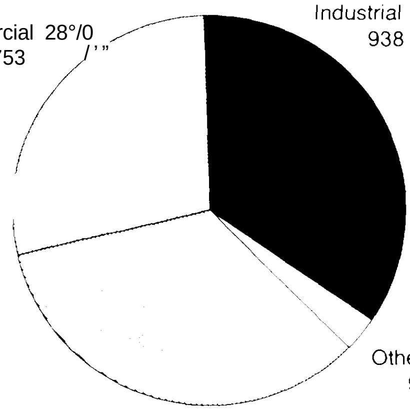
a includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

bincludes only those power plants with a fossil-fueled, steam-e nameplate capacity (existing or planned) of 10 or more megawatts,

NOTES: Data on capabliity, generation, consumption, stocks, receipts, and costs of fossil fuels for 1990 are final; other 1990 data are preliminary. Totals may not equal sum of components because of independent rounding.

SOURCE: Office of Technology Assessment, 1993, based on information in U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 1990,* DOE/EIA-0348(90) (Washington, DC: U.S. Government Printing Office, January 1992).

Figure 3-3-Electricity Sales by Sector (billion kWh)



SOURCE: Office of Technology Assessment, 1993 based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 7990, DOE/EIA-0384 (90)* (Washington, DC: U.S. Government Printing Office, May 1991), table 94, p. 215.

into avoided fuel and capacity savings on the supply side.

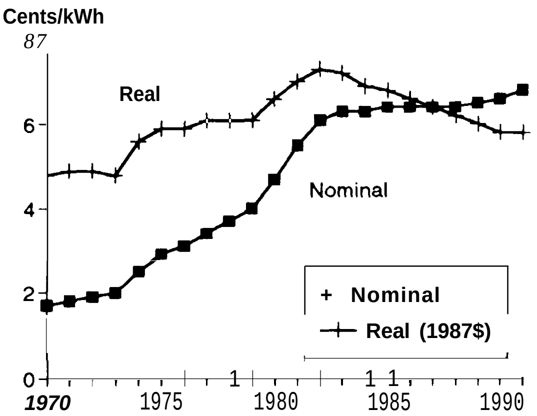
Revenues and Capital Investments

Electricity sales and capital investments make electric utilities an influential force in the economy. In 1990, consumers paid over $179 billion for electric power.[4] Table 3-1 and figure 3-3 show power sales and revenues by customer class, The retail cost of electricity varies significantly among the customer classes. Industrial customers generally are charged less per kilowatt-hour (kWh) than residential or commercial customers. Utilities justify this on the basis of lower costs incurred to serve industrial customers with large loads and often a single point of delivery, compared with residential service characterized by many dispersed customers with relatively low individual electricity sales volumes and higher associated transmission and distribution investment and electricity losses per kilowatt-hour sold. Lower prices are also justified to maintain market share and to discourage industrial customers from leaving the system by turning to natural gas or self-or cogeneration for energy needs—which could result in stranded investment costs that must be borne by remaining customers in the form of higher rates.

On a national average, the nominal price of electricity in 1990 was 6.6 cents/kWh, up from

[4] *Public Power*, Annual Statistical Issue, vol. 50, No. 1, January-February 1992, p. 56.

Figure 3-4-Average Retail Electricity Prices, Nominal and Real (1987 dollars)



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review* 1991, DOE/EIA-0384 (91) (Washington, DC: U.S. Government Printing Office, June 1992), table 102, p. 229.

4.7 cents/kWh in 1980. However, real electricity prices have, on average, declined during the last decade (as shown in figure 3-4). Adjusting for inflation, average retail electricity prices in 1990 of 5 cents/kWh are 10 percent less than they were in 1980.[5]

The utility industry is highly capital-intensive. Investor-owned utility capital investment in plant and equipment was valued at $379 billion in 1990.[6] Total assets of public power systems and rural electric cooperatives were estimated at $125.8 billion in 1990.[7] Estimates of new construction spending for investor-owned utilities were some $26.3 billion in 1990 according to one industry survey.[8] The largest share of this capital investment, $13.6 billion, was earmarked for transmission and distribution construction and improvements; only $8.9 billion was for building new generating plants-a shift from the massive new powerplant construction expenditures of the 1970s and early 1980s.

Environmental Impacts

Electric power generation is a significant source of air pollution and carbon dioxide (CO_2) emissions and thus has been a focus of environmental protection and cleanup efforts. In 1990 electric utilities' fossil-fired steam electric-generating plants spewed 16.5 million tons of sulfur dioxide (SO_2), 7.1 million tons of, nitrogen oxides (NO_x), and 1,979 million tons of carbon dioxide into the air.[9] According to data collected by the U.S. Environmental Protection Agency (EPA), burning of sulfur-laden coal and residual fuel oil by electric utilities accounted for over 80 percent of SO_2 emissions in 1989.[10] Electric utilities also were the source of some 60 percent of NO_x emissions in that year, Electric generation is responsible for about 35 percent of total carbon emissions in the United States and electric utilities account for almost all of these emissions.[11] Any strategy to limit carbon emissions to offset threats of global climate change will of

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[5] DOE, *Annual Energy Review 1991,* supra note 1, p. 229, table 102.

6 ‘‘SWcl~ Report: 1991 Annual Statistical Report Utility Construction Stirs as NUG Plans Grow, ’ *Electrical World,* April 1991, pp. 9-14. See also U.S. Department of Energy, Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities,* DOE/EIA-0437(90)/1 (Washington, DC: U.S. Government Printing Office, January 1992).

[7] U.S. Department of Energy, Energy Information Administration *Financial Statistics of Selected Publicly Owned Electric Utilities 1990,* DOE/EIA-0437(90)/2 *(Washington DC:* U.S. Government Printing Office, February 1992).

[8] *Electrical World,* supra note 6, p. 9.

9 DOE, *Annual Energy Review 1991,* supra note 1, p. 227, table 100.

10 U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *National Air Pollutant Emission Estimates 1940-1989, EPA-450/4-91-004,* March 1991. According to the same report, utility emissions of sulfur oxides in 1989 would have been approximately 60 percent higher without the installation of pollution control equipment required by the Clean Air Act.

11 See U.S. Congress, Office of Technology Assessment, *Changing by Degrees: Steps to Reduce Greenhouse Gases,* OTA-O-482 (Washington DC: U.S. Government Printing Office, February 1991), p. 8.

necessity target electricity generation—and increase the attractiveness of energy efficiency alternatives through demand-side management (DSM).

The Federal Clean Air Act required installation of pollution controls at electric generating plants, reducing emissions and spurring the development of cleaner, state-of-the-art powerplants. Stringent new acid precipitation provisions of the Clean Air Act Amendments of 1990 will require electric utilities to make further reductions in their emissions of SO_2 and NO_x starting in 1995. These requirements will fall most heavily on Eastern and Midwestern utilities now burning high sulfur coal and potentially involves billions of dollars in new investment in control technologies to be paid for by ratepayers. One potential result could be the accelerated retirement or life-extending repowering of older plants. The 1990 Amendments also offered utilities another option for compliance. The option was to buy emissions allowances-a kind of license to pollute-from other utilities who have reduced their emissions below required levels, This innovative 'market-based' approach to environmental regulation-a new system of tradable pollution allowances-was included in the 1990 acid rain amendments and provides a further spur to utilities to install pollution control equipment, participate in integrated resource planning, and invest in energy efficiency in their operations.[12] The amendments established the Conservation and Renewable Energy Reserve to award additional emission allowances to utilities that cut emissions by installing electricity-saving DSM measures or by using renewable energy resources.[13]

In addition to air quality impacts, other environmental effects associated with electric power generation are the extraction and processing of fossil and nuclear fuel; construction and operation of hydroelectric, geothermal, solar, and wind facilities; and waste to energy plants.[14] Siting, construction, and operation of the plants can create local land-use conflicts, congestion and noise impacts on neighbors, and adverse impacts on natural habitats and wildlife. Power generation contributes to water and waste pollution. Nuclear power and handling and disposal of nuclear waste also entail a special set of serious, contentious, and long-term environmental issues because of the radiation hazards. Opportunities to use energy more efficiently are also opportunities to avoid associated environmental impacts of energy production.

Electric power transmission and distribution also have associated environmental impacts beginning with local land-use conflicts in the siting of power lines and substations. The construction phase contributes to erosion, soil compaction, destruction of forests and natural wildlife habitat in the right of way. During operation, nuisance effects include visual impacts, audible noise, corona effects, and interference with radio and television reception. Transmission systems can have deleterious effects on local bird life through collisions with powerlines and towers and electrocutions. Use of chemical herbicides and other vegetation management techniques along rights of way raises concerns about ecological impacts in some areas. In recent years, the as-yet-unproven possibility of human health effects from exposure to electric and magnetic fields has

12 Public Law, 101-549, sec. 404(f), Nov. 15, 1990, 104 Stat. 2601,42 U.S.C. 7651c(f).

13 See ch. 7 of this report.

14 Environmental impacts of electric utility activities are S ummarized in ch. 7 of U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Options to Increase Competition,* OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989), hereinafter OTA, *Electric Power Wheeling and Dealing.*

become a prominent concern in siting transmission and distribution facilities.[15]

Industry Structure

Electric utilities are the largest component of the electric power industry, a diverse patchwork of investor and publicly owned utilities; consumer cooperatives; Federal, State, and local government agencies; cogenerators; and independent power producers. The distinguishing characteristic of most electric utilities is that they are regulated monopolies that sell power to retail customers.

America's more than 3,200 regulated electric utilities supply electricity to over 110 million households, commercial establishments, and industrial operations. The differences among utilities in size, ownership, regulation, customer load characteristics, and regional conditions are important for policy. Table 3-2 shows selected statistics for the electric utility sector by type of ownership. Utility ownership and location determine regulatory jurisdiction over utility operations and rates.

Investor-Owned Utilities

The 267 investor-owned utility (IOU) operating companies dominate the electric power industry, generating 78 percent of the Nation's power in 1990 and serving about 76 percent of all retail customers. IOUS are private, shareholder-owned companies ranging in size from small local operations serving a customer base of a few thousand to giant multistate corporations serving millions of customers. Most IOUS are vertically integrated, owning or controlling all the generation, transmission, and distribution facilities required to meet the needs of the customers in their assigned service area.

IOUS can be found in every State except Nebraska. Their local operations and retail rates are usually highly regulated by State public utility commissions, however their wholesale power sales and wheeling (power transmission) contracts fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Control over IOUS is further concentrated because many of them are actually subsidiaries of utility holding companies. Nearly one-quarter of the IOU operating companies are subsidiaries of registered electric utility holding companies regulated under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission and FERC. The following are registered utility holding companies: Allegheny Power System, Inc., American Electric Power Co., Central and South West Corp., Eastern Utilities Associates, General Public Utilities Corp., Entergy Corp., New England Electric System, Northeast Utilities, and The Southern Co. In addition to the registered holding companies, many other utilities are also part of holding company systems consisting of affiliated utility subsidiaries operating intrastate or in contiguous States and, thus, are exempt from detailed oversight under PUHCA.

Publicly Owned Electric Power Systems

The more than 2,000 public power systems include local, municipal, State, and regional public power systems ranging in size from tiny municipal distribution companies to giant systems like the Power Authority of the State of New York. Publicly owned systems are in operation in every State except Hawaii. Together, local public power systems generated 9 percent of the Nation's power in 1990 but accounted for 14 percent of total electricity sales, reflecting the fact that

15 U.S. Congress, Office of Technology Assessment, Biological *Effects of Power Frequency Electric and Magnetic Fields,* Background Paper, O-IA-BP-E-53 (Washington, DC: Us. Government Printing Office, May 1989). Several epidemiologic studies have been published suggesting a link between magnetic field exposures in the vicinity of local distribution lines and increased risk of childhood cancer. Public health concerns have resulted in increased research funds for investigating this possible health hazard in hopes of determining what risks, if any, exist and how tbey might be mitigated. In the meantime, utility commissions and utilities are now increasingly including assessments of electric and magnetic field exposures and field reduction alternatives in the consideration and approval of new transmission facilities.

Table 3-2—U.S. Electric Utilities, Selected Statistics, 1990

Type of utility	Number	Ultimate consumer[a]		Sales to ultimate consumers		Revenues from sales to ultimate consumers		Installed generating capacity		Net generation[c]	
		Millions	Percent	Billion kWh	Percent	$billions	Percent	GW[b]	Percent	Billion kWh	Percent
investor-owned.	267	84	76	2,071	71	140	79	529	77	2,203	78
Publicly owned[d].	2,011	15	13	386	14	23	13	71	10	245	9
Cooperatives.	953	12	11	201	7	14	8	25	4	126	4
Federal[e].	10	<1	0	55	2	2	1	65	9	235	8
Total.	3,241	111		2,713		178		690		2,808	

a Ultimate consumers in most instances are retail customers.
b GW, or gigawatt, is 1 billion watts.
c Includes 116 billion kWh purchased from nonutility generators.
d Publicly owned utilities are local nonprofit government agencies including municipal, public power districts, irrigation districts, State power authorities, and other State organizations.
e Federal utilities include the electric power Operations of the Federal power marketing administrations and the Tennessee Valley Authority.

SOURCE: Office of Technology Assessment, 1993, based on information from the U.S. Department of Energy, Energy Information Administration, Electric *Power Annual* 1990, DOE/EIA 0348(90) (Washington, DC: U.S. Government Printing Office, January 1992).

many public systems are involved only in retail power distribution and purchase power supplies from other utilities.

The extent of regulation of public power systems varies among States. In some States the public utility commission exercises jurisdiction in whole or part over operations and rates of publicly owned systems. In other States, public power systems are regulated by local governments or are self-regulated. Municipal systems are usually run by the local city council or an independent board elected by voters or appointed by city officials. Other public power systems are run by public utility districts, irrigation districts, or special State authorities.

Rural Electric Cooperatives

Electric cooperatives are electric systems owned by their members, each of whom has one vote in the election of a board of directors. They can be found in 46 States and generally operate in rural areas. In 1990, rural co-ops accounted for 4 percent of total power generation and 7 percent of sales to ultimate customers.

Congress created the Rural Electrification Administration (REA) in 1935 to bring electricity to rural areas and subsequently gave it broad lending authority to stimulate rural electricity use. Cooperatives have access to low-cost govemment-sponsored financing through REA, the Federal Financing Bank, and the Bank for Cooperatives. Early REA borrowers tended to be small cooperatives that purchased wholesale power for distribution to members. Over the past 20 years, however, many expanded into generating and transmission cooperatives in order to lessen their dependence on outside power sources.

Regulatory jurisdiction over cooperatives varies among the States, with some States exercising considerable authority over rates and operations, while other States exempt cooperatives from State regulation. In addition to State regulation, cooperatives with outstanding Federal loans fall under the jurisdiction of REA, which imposes various conditions intended to protect the financial viability of borrowers.

Federal Power Systems

The Federal Government is primarily a wholesaler of electric power produced at federally owned hydroelectric facilities and has less than 25,000 retail customers directly served by its systems. Together, Federal systems had an installed generating capacity of approximately 65 gigawatts (GW) and accounted for 8 percent of the Nation's power generation in 1990. All Federal power systems are required under existing legislation to give preference in the sale of their output to other public power systems and to rural electric cooperatives.

Federally owned or chartered power systems include the Federal power marketing administrations, the Tennessee Valley Authority, and facilities operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, the Bureau of Indian Affairs, and the International Water and Boundary Commission. Wholesale power is marketed through five Federal power marketing agencies:

1. Bonneville Power Administration,
2. Western Area Power Administration,
3. Southeastern Power Administration,
4. Southwestern Power Administration, and
5. The Alaska Power Administration.

The Tennessee Valley Authority is an independent government corporation that sells power within its statutory service area. Jurisdiction over Federal power systems operations and the rates charged to their customers is established in authorizing legislation. More on these Federal utility systems can be found in chapter 7 of this report.

ELECTRIC POWER REGULATION

The electric utility sector is one of the most heavily regulated industries in the U.S. economy with virtually all aspects of power generation, transmission, and distribution under the oversight of State and/or Federal agencies. Like other businesses, the electric power industry is subject to laws and regulations governing financial transactions, employment practices, health and safety, and environmental impacts. But unlike other businesses, as a public utility, it (along with segments of the natural gas, telecommunications, and transportation industries) is subject to additional economic regulation. Economic regulation of public utilities encompasses organizational and financial structure, prices (rates), profits, allocations of costs, franchise territories, and terms and conditions of market entry and exit—matters that for unregulated entities are normally determined by management discretion and market forces. Economic regulation of public utilities is exercised by Federal, State, and local bodies. Which regulatory body has controlling jurisdiction typically depends on the type of utility, the transaction involved, and State and Federal law. It is not at all unusual for both State and Federal regulators to be involved in review of some utility decisions.

The Concept of a Public Utility

Public utilities enjoy a special status under State and Federal law because their activities provide vital services to businesses and communities (sometimes phrased as "affected with the public interest"). This status confers specific rights and obligations and distinguishes them from most other business enterprises. Generally, a public utility has an obligation to:

- serve all customers in its service area (within its available capacity limitations);
- render safe and adequate service, including meeting foreseeable increases in demand;
- serve all customers within each service class on equal terms (i.e., with no unjust or undue discrimination among customers); and
- charge only a' 'just and reasonable price for its services.[16]

In return for assuming these obligations, the public utility enjoys certain "rights." First, the utility has a right to reasonable compensation for its services, including a profit on capital investment to serve the public. Second, through its franchise and certificate of public convenience and necessity, the utility generally is protected from competition from other enterprises offering the same service in the same service territory. Third, the public utility has a right to conduct its operations and render service subject to reasonable rates and regulations. Finally, in many States public utilities can exercise the right of eminent domain to condemn and take private property for public use where necessary to provide adequate service, subject to the requirement of just compensation to the owner.[17]

Both State and Federal laws define any entity that sells electricity as a public utility,[18] thus bringing generators and retail distributors of electricity under regulation, unless provided with an explicit exception. Jurisdiction over the activities of electric utilities is split between the Federal Government and State agencies (including local governments). This division reflects both the historical growth of electric utility regulation in this country, which began at the State and local level, and the Federal Government's constitutional authority over interstate commerce. Many utilities are now directly or indirectly subject to both Federal and State rate regulation.

16 Charles F. Phillips, Jr., *The Regulation of Public Utilities: Theory and Practice* (Arlington, VA: Public Utilities Reports, Inc., 1984), p. 106.

17 Ibid., p. 107.

18 The definition of an electric utility in the Federal Power Act 1S: "any person or State agency which sells electric energy, " 16 U.S.C. 7%(22), and the definition of 'electric utility company' in the Public Utility Holding Company Act is ''any company which owns or operates facilities used for the generation transmission or distribution of electric energy for sale, " 15 U.S.C. 79b(a)(3).

State Regulation

State regulation of electric power is diverse, but four broad generalizations can be made about the form and extent of government oversight exercised.[19]

1. **State regulatory jurisdiction over utility rates** and operations is typically vested in independent multimember boards or commissions whose members are either appointed or elected.
2. State (or local government) regulators control market entry by granting certificates of public convenience and necessity to electric utilities--creating what are usually monopoly franchise territories.
3. All States regulate retail prices of electricity. In setting retail rates, State regulators must approve a level that covers the utility's cost of providing service and a reasonable rate of return to the utility and its shareholders. Under various formulations, many States require that utility investments be determined to be prudent and "used and useful" before they can be recovered through retail rates. Some States allow recovery for plants under construction, while others defer recovery until the plant is actually in operation.
4. State regulators also exercise control over utility securities (e.g., stock issuance, stock classifications) and financing arrangements (bonds, loans, and other debt transactions). This oversight was instituted because of the historical abuses by public utility holding companies and was intended generally to prevent use of utility assets for nonutility ventures and to protect the financial integrity of the utility.

The extent of State commission jurisdiction over utilities varies. Some States regulate all utilities, including public power systems and cooperatives, while others limit jurisdiction to investor-owned systems and leave regulation of municipal systems to local governments.

Many States also regulate other aspects of utility operations in some detail, including the planning and determination of resource needs such as new generation, bulk power purchases, and construction of transmission and distribution facilities.[20] A number of States regulate the siting of utility facilities either through the public utility commission or a separate siting agency.[21]

In some **States** public utility regulators have a more general mandate to protect and/or promote the public interest and welfare. This mandate has been interpreted as supporting other policy goals for utility regulation, such as economic development, universal electric service, minimum levels of service at equitable or affordable rates, and environmental protection.

RETAIL RATE REGULATION

Regulators establish the rates charged to customers, as well as their view of appropriate profit levels for utilities, through administrative proceedings. Under the most common ratemaking approach-variously referred to as rate-of-return regulation or cost-of-service regulation or traditional rate regulation-the utility commission sets retail rates based on estimates of the expected costs of service to meet projected customer demand (i.e., kilowatt-hour sales).

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19 For a more detailed discussion of State and Federal utility regulation, see Congressional Research Service, *Electricity: A New Regulatory Order?* Committee on Energy and Commerce, U.S. House of Representatives, 102d Cong., 1st sess., Committee Print 1O.2-F, June 1991.

20 For a summary of State requirements for utility planning and forecasting requirements, see Public Utilities Commission of the State of Ohio, *Transmission Line Certification and Siting Procedures and Energy Planning Processes: Summary of State Government Responses to a Survey by the National Governors' Association Task Force on Electricity Transmission*, contractor report prepared for the Office of Technology Assessment, July 1988.

21 For more information, see the discussion of State siting requirements in ch. 7 of OTA, *Electric Power Wheeling and Dealing,* supra note 13.

Box 3-A-The Revenue Requirement

A utility's revenue requirement is the total number of dollars required to cover its operating expenses and to provide a fair profit. This rate setting method is sometimes called the fair return on fair value rule. The revenue requirement is often expressed in a formula:

$$RR= OE + CD + (OC + 1- D)r$$

Where

RR. the revenue requirement (total dollars to be raised);

OE = operating expenses (e.g., fuel, maintenance, salaries, benefits, taxes, and insurance);

CD= current depreciation (on utility plant and equipment);

OC = original cost of capital employed in service to the public, sometimes partly adjusted for inflation;

I = Improvements in capital employed;

D - accumulated depreciation (in the value of capital employed); and

r. rate of return (percent earnings on the value of the capital employed in the business set by the regulators taking into account the utility cost of equity and debt capital, performance, and returns on similar investments).

In the above formula:

(OC-I-D) = rate base (net valuation)

(OG-I-D)r = profit expressed as earnings on the rate base.

SOURCE: Office of Technology Assessment, 1993, adapted from Congressional Research Service, Electricity:A New Regulatory Order? Committee on Energy and Commerce, U.S. House of Representatives, 102d Cong., 1st sess., Committee Print 102-F, June 1891, p. 137, citing Jones and Tybout, "Environmental Regulation and Electric Utility Regulaton: Compatibility and Conflict," Boston College Law Review, vol. 14, 1986, pp. 43-44 (1986).

Retail rates are typically set based on the utility's revenue requirement, i.e., the estimated revenues required to cover operating expenses. These expenses include: administrative, financing, and marketing costs; personnel, fuel, maintenance, purchased power, and other operating costs; plus recovery of capital investment in the rate base (plant and equipment committed to public service less depreciation). A percentage profit (rate of return) on all investments included in the rate base is also included in the revenue requirement for investor-owned utilities. (See box 3-A.) What capital investments are included in the rate base and what expenses are allowed are left to the broad discretion of regulators, as is judgment of what is a fair and reasonable rate of return. The utility too has some leeway in allocating expenses and capital costs in its submissions for ratemaking. State policies and regulations differ in formulations of matters included or recoverable through rates, including treatment of construction work in progress (investment in facilities that are not yet in operation). There are also variations in classes of customers, and related issues such as the availability of basic or lifeline rates for low-income customers.

After establishing the revenue requirement, State regulators must then determine how those funds will be collected from customers-referred to as the rate structure or the rate schedule. The revenue requirement is divided by estimates of expected sales to yield the rate per kilowatt-hour that is used to calculate the customer's bill. Typically, different rates are established for different classes of customers. The rate design for each class must yield a price (per kilowatt-hour) that will produce sufficient revenue to cover the costs of serving that class and contribute to meeting the overall revenue requirement. Rates are revised periodically to reflect changes in utility investments and performance and general economic conditions.

Because fuel prices can vary considerably in response to market conditions, most States have a separate fuel adjustment clause, a mechanism intended to insulate utilities from fuel price swings. The automatic fuel adjustment clause allows utilities to raise or lower fuel charges on customer bills to follow fuel costs as they are incurred instead of waiting for a rate case.

There is no single approved constitutional method of ratemaking. The U.S. Supreme Court has held that the Constitution gives States broad discretion to decide which rate-setting mechanism best meets their needs in balancing the interests of the utility and the public.[22] The rate base method for determining just and reasonable rates for public utilities as long as they are not confiscatory was upheld by the Supreme Court in *Hope Natural Gas Company v. Federal Power Commission* .23

With utility profits under traditional ratemaking based on the total value of capital invested and the amount of power sold, many analysts have concluded there is a tremendous financial incentive for utilities to invest heavily in capital-intensive plant and equipment and to sell as much power as they can at prices above their cost of service.[24] This incentive is counterbalanced by the threat of penalties and disallowances by their regulators. For example, regulators have developed certain general principles limiting investments included in the rate base:

- Negligent or wasteful losses that are the fault of the utility management cannot be included as operating charges.
- Investments must be prudent--i.e., reasonable under ordinary circumstances and at the time made. Recovery of costs from uncontrolled cost overruns, construction mismanagement, or plant abandonment can be disallowed as imprudent.

Some States further specify that the plant must actually be in service to the public to qualify for inclusion in the rate base.*

A utility's profits from electricity sales are supposed to reflect regulators decisions about appropriate returns on prudent capital investments in rate base. While regulatory authorities cannot force a utility to operate at a loss, recovery of a utility's authorized rate of return is not guaranteed. At times, the utility may not actually earn its authorized rate of return because of adverse economic conditions, poor business judgment, or because regulators overestimated actual sales. If a utility sells fewer kilowatt-hours than projected in the rate case, its actual revenues will be lower than assumed and, accordingly, its profits will be less than authorized. If, however, the utility sells more kilowatt-hours than projected, its revenues and profits will be higher, assuming that the marginal cost of generating the additional kilowatt-hours is less than the sales price. This is usually the case, because automatic

22 Congressional Research Service, supra note 18, pp. 619-620.

23 320 U.S. 591 (1944).

24 315 Us. 575 (1942).

25 In *Dusquenne Light Co. v. Barasch*, 109 S. Ct 609, Jan. 11, 1989, the U.S. Supreme Court upheld the Pennsylvania statutory requirement that a utility plant must be "used and useful in service to the public" to be includable in the rate base against claims that such a requirement in the case of canceled plants violated constitutional protections for due process and just compensation. The ruling affirmed the State utility commission decision precluding recovering initial costs of a canceled, unfinished nuclear plant even though the costs were prudently incurred by the utility at the time.

fuel adjustment clauses operate to reduce risks to utility profits from fuel price changes. This built-in incentive toward additional sales is what gives rise to the claim that traditional utility ratemaking is biased against utility investment in conservation and energy efficiency.

If the costs of serving additional consumption exceeded the established rates per kilowatt-hour, the financial incentives would change and utilities would profit by restraining demand, However, the immediate cost of procuring or generating additional kilowatt-hours usually falls well below the rates at which utilities are permitted to sell them, thus providing a powerful incentive for utilities always to increase power sales and to resist efforts to lower sales.

Under conventional rate-of-return regulation, short-term profit considerations favor increased sales of kilowatt-hours, especially in situations of surplus capacity that is cheap to operate. Recognition of this tendency has lead State regulators, spurred in large part by consumer and environmental activists, to adopt various measures to insulate or ''decouple' shareholder returns from the volume of kilowatt-hours sold.[26] One such device is the Electricity Revenue Adjustment Mechanism (ERAM) used in California and in variations in other States, in which customer rates are automatically adjusted upward or downward so that the utility meets, but does not exceed, its revenue requirement set in prior rate proceedings. These approaches are discussed in chapter 6 of this report.

Ratemaking is not an exact science, although, as practiced today, it relies heavily on economics, statistics, computer modeling, and expert testimony. Much of the regulators' work is political in nature. Fundamentally regulators seek tradeoffs among often competing policy goals of economic efficiency, adequate and reliable service, environmental quality, and equity.

Assuring Quality of Service

Most State commissions are expressly em-powered to assure that utilities provide adequate and reliable service for their retail customers. The obligation generally means that a utility must provide safe, continuous, comfortable, and efficient electric service within its service area. However, the utility is not required to supply power under any and all conditions, such as during severe storms or power outages beyond their control. To provide reliable service, utilities are required to plan to meet reasonably foreseeable contingencies and load growth.

Regulators have several mechanisms for enforcing this obligation. They can punish chronically poor, unreliable, and inefficient service by denying or reducing rate increases. The commission can order the utility to take specific remedial actions to improve service, such as acquiring additional generation or transmission facilities, or executing power purchase contracts. Finally, under certain circumstances varying by jurisdiction, utilities can be held financially liable for injuries or damages to their customers caused by inadequacy, interruption, or failure of electric services.

Energy Efficiency, Resource Planning, and Demand-Side Management

With their plenary authority over retail rates and the construction of electric power facilities, State regulators can exercise considerable influence over utility resource planning and operations. In response to the sizable rate increases and disputes over new powerplant construction that arose in the late 1970s, many utility commissions adopted policies encouraging or requiring utilities to engage in demand-side management (DSM) programs and integrated resource planning (IRP). Several commissions have also adopted incentives or requirements for improvements in the energy efficiency of utilities' supply-side opera-

26 Ralph C. Cavanagh, ''Responsible Power Marketing in an Increasingly Competitive Era,'' *Yale Journal on Regulation*, vol. 5, summer 1988, pp. 331-366.

tions. These requirements are generally intended to lower electricity costs for consumers by encouraging the use of cost-effective energy efficiency measures as an alternative to higher-cost conventional generation. Some policies also have been adopted to support environmental protection, and promote diversity of energy sources. Chapter 6 of this report provides an overview of these State efforts.

The legal basis for requiring utility IRP and DSM varies by State. Some requirements are backed by legislation, others are the result of broad rulemakings by State regulatory commissions, and still others have arisen out of rate cases involving specific utilities. By the 1990s State regulatory requirements for utility planning activities were firmly established in more than 30 States and under development in many others. At the same time, a broad range of financial incentives intended to encourage utility investment in DSM programs had also been adopted by States. These changes are altering the relationship between utilities and their regulators and shifting the financial incentives in utility ratemaking.

Federal Regulation

JURISDICTION

The Federal Power Act gave the Federal Power Commission authority over the rates and conditions for interstate sale and transmission of electric power at wholesale.[27] Federal regulation of interstate and wholesale sales was initially seen as a supplement to State authority to fill a gap where existing State regulation had proven ineffective or unconstitutional. The creation of a Federal role in the regulation of interstate activities in electric power was prompted by the 1927 Supreme Court ruling in *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric Co.* that State regulatory agencies were constitutionally prohibited from setting the prices of electricity sold across State lines because doing so would violate the Commerce Clause.** This decision created a gap in effective regulation of electric utilities that the Federal Power Act was intended to close.

Originally, it was perceived that there was a bright line between Federal and State jurisdiction—Federal regulators would have jurisdiction over wholesale transactions involving more than one State and State commissions would oversee utility operations, instate wholesale transactions, and retail rates. But, as interconnections among utilities grew and long-distance transmission increased, virtually all electric power moving over transmission lines was viewed as being in interstate commerce and, hence, subject to exclusive Federal jurisdiction. These ever-more expansive interpretations of Federal jurisdiction have now brought wholesale transactions between utilities in a single State, as well as most instate wheeling arrangements, under Federal law. These rulings and the fact that most utilities are interconnected with utilities in other States have arguably limited most State jurisdiction over prices and terms of wholesale sales and wheeling transactions, even when they involve instate parties--except in Alaska, Hawaii, and parts of Texas.[29]

27 Public Utility Act of 1935, Act of Aug. 26, 1935, c. 687, Title II, sec. 213,49 Stat. 863, 16 U.S.C. 791a-825r, as amended.

28 This landmark Supreme Court case, *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric CO., 273* U.S. 83 (1927), held that a State could not regulate the price of electricity generated in that State and sold in another. It reflected the then prevailing view that the Commerce Clause of the Constitution gave the Federal Government exclusive jurisdiction to regulate matters in interstate commerce and foreclosed State action to intrastate matters even in the absence of Federal regulation.

29 See *Federal Power Commission* v. Southern *California Edison Co., 376* U.S. 205 (1%8), also known as *City of Colton* v. *Southern California Edison Co, See also Florida Power & Light Co., 29* FERC *61,140 (1984), in* which FERC asserted exclusive Federal jurisdiction over virtually all transmission service in Florida. Because the power systems in the ERCOT region of Texas, and in Alaska and Hawaii, are not synchronously connected to power systems in other States, it has been widely assumed that FERC does not have jurisdiction over most power transactions in these States.

With the establishment of the U.S. Department of Energy (DOE), the responsibilities of the Federal Power Commission for regulating electric utilities, natural gas pipelines, and oil pipelines were transferred to a new agency, the Federal Energy Regulatory Commission.[30] Its five members are appointed by the President and confirmed by the Senate to staggered, fixed terms; no more than three commissioners may come from the same political party. Although within DOE, FERC retains its independent status. The Secretary may submit his or her views on energy policy to the commission, but the Secretary cannot direct the commissioners to reach a particular result.[31]

The Federal Power Act, as amended, gives FERC jurisdiction over the prices, terms, and conditions of wholesale power sales involving privately owned power companies and of transmission of electricity at wholesale.[32] It also oversees sales and mergers of public utilities,[33] the issuance of securities and indebtedness of electric utilities,[34] and power pools and utility interconnections.[35] In addition, FERC approves the rates for public power sold and transported by the five Federal power marketing administrations, and oversees and licenses nonfederal hydroelectric projects on navigable waters.[36]

The Public Utility Regulatory Policies Act of 1978 (PURPA) gave FERC expanded responsibilities for encouraging cogeneration and certain alternative power technologies.[37] PURPA required utilities to interconnect with and buy power from cogenerators and small power producers that met standards established by FERC at not more than the utility's avoided cost of power.[38] PURPA marked the frost major Federal move to open up electricity markets to nonutilities. At the same time, PURPA exempted these qualifying facilities (QFs) from most of regulatory burdens applicable to public utilities under Federal and State law in order to reduce the institutional barriers to QF development.

PURPA also imposed new requirements directly on State regulatory commissions relating to the consideration of regulatory policy initiatives and consumer protection and representation before State commissions. PURPA required State commissions to give formal consideration to adopting certain new Federal standards as part of State utility law and policy, but PURPA also expressly provided that States could, after such consideration, decline to implement the standard. Many of the proposed standards were already being used by State regulators to ensure that rates more accurately reflect the costs of providing service and to encourage energy conservation. The Federal standards included certain ratemaking methods: seasonal, time of use, and interruptible rate differentials; limiting declining block rate (e.g., large volume) discounts unless they involved lower service costs; and requiring utilities to offer load management technologies to their customers. Federal standards were also proposed

30 The Department of Energy Organization Act, Public Law 95-91, Title IV (1977), 42 U.S.C. 7101 et seq. FERC also regulates interstate natural gas pipeline transactions and oil pipelines.

31 Congressional Research Service, supra note 18, p. 129, citing Grenier and Clark, "The Relationship between DOE and FERC: Innovative Government or Inevitable Headache," *Energy Law Journal*, vol. 1, 1980, p. 325.

32 See secs. 201 and 205 of the Federal Power Act, 16 U.S.C. 824a and 824d, respectively.

33 Section 203 of the Federal Power Act, 116 U.S.C. 824b.

34 16 U.S.C. 824c.

35 16 U.S.C. 824b.

36 Title I of the Federal Power Act, 116 U.S.C. 791a to 823.

37 Public Law 95-615, 92 Stat. 3117, Nov. 9, 1978.

38 Avoided cost generally means a price not exceeding the cost of electric energy that the utility would otherwise have to generate itself Or purchase from another source. Public Law 95-615, sec. 210,92 Stat. 3144, 16 U.S.C. 824a-3.

for consumer information, lifeline rates, and procedures for terminating electricity service. Not surprisingly, PURPA was challenged in the Courts. However, the Supreme Court ruled that this Federal intrusion into matters previously left to the States was found to be within the broad embrace of the Commerce Clause.[39]

FERC shares responsibility for enforcing the Public Utility Holding Company Act of 1935 (PUHCA) with the Securities and Exchange Commission (SEC).[40] PUHCA vests broad authority over the structure, finances, and operations of public utility holding companies in the SEC. PUHCA was enacted in response to widespread concern over the influence of a handful of large interstate utility holding companies that by 1932 controlled over 75 percent of the private electric utilities.[41] PUHCA was intended to limit severely the use of the holding company structure and to force the regional consolidation of the existing large multistate holding companies.

WHOLESALE RATEMAKING[42]

The Federal Power Act requires that rates charged for wholesale power sales and for transmission be "just and reasonable" and "not unduly discriminatory or preferential."[43] Utilities under FERC jurisdiction must file detailed, written tariffs and schedules of all rates and charges, which are available for public inspection. FERC has established detailed regulations and guidelines on rate requests, allowable costs, and matters considered in rate of return determinations. FERC also requires that electric utilities follow a uniform system of accounting.

Proposed new rate schedules must be filed with FERC 60 to 120 days before they are to go into effect. Utilities must submit detailed schedules of information, including actual and projected cost of service data to support the increases. When a proposed new rate is filed, FERC has several choices: it can reject the filing, approve the rate schedule immediately, or order a hearing and suspend the new rate for 5 months. If FERC schedules a hearing, the burden of proof is on the utility seeking the rate increase. The Commission must also consider evidence submitted by customers or other interested parties. Parties to proceedings can seek review in Federal Courts of Appeals, where the standard is whether the agency decision is supported by substantial evidence.

FERC decisions are made on a case-by-case basis. However, over the years a substantial body of administrative precedent has accumulated that guides the commission and applicants. FERC is not wholly bound by precedent, however. Within its broad and general authority under the Federal Power Act, the commission can establish new policies on electric power transactions through

39 *Federal Energy Regulatory Commission* v. *Mississippi, 456* U.S. 742 (1982).

40 Act of Aug. 26, 1935, c. 687, Title I, sec. 33, 49 Stat. 438, 15 U.S.C. 79.

41 The holding companies' complex corporate structures and interlocking business arrangements had frustrated both State and Federal oversight of their activities, led to substantial investment fraud, and weakened or bankrupted many local gas and electric utilities. For more on the structure and influence of the holding companies, see Leonard S. Hyman, *America's Electric Utilities: Past, Present and Future,* 3d Ed. (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 71-83.

42 For more background on Federal power regulation, see Congressional Research Service, supra note 18, pp. 135-144.

43 16 U.S.C. 824d and 824e. The term ''just and reasonable' as used by Congress in the Federal Power Act in 1935 had been established by decades of judicial review of administrative actions governing public utilities *Farmers Union Central Exchange, Inc. et al. v. Federal Energy Regulatory Commission*, 734 F2d 1486, at p. 1502 (D.C. Circuit, 1984). In that case, the court reviewed basic principles of rate regulation observing that Courts will uphold agency rate orders that fall within a ''zone of reasonableness' where rates are neither "less than compensatory" nor "excessive." The zone of reasonableness requires striking a fair balance between the financial interests of the regulated company and ''the relevant public interests. ' In determining the reasonableness of rates to a producer, the concern is whether the rate is high enough to cover the cost of debt and expenses and provide a return commensurate with investments in other enterprises with comparable risks in order to maintain credit and attract capital. In deciding the justness and reasonableness to the consumer, the concern is whether the rate is low enough to prevent exploitation by the regulated business.

individual case decisions or in new rulemakings. When FERC departs from past policies, however, it must provide ample justification and documentation of its decision in the face of possible court challenges.

In approving wholesale rates, FERC historically has followed a cost of service approach that is, in principle, similar to that used by State regulators. As with State rate regulation, Federal economic regulation is based, in part, on lack of effective competition in bulk power markets. However, during the Reagan and Bush Administrations, FERC chairmen and staff embraced the market deregulation rhetoric of the times and embarked on several initiatives with the goal of allowing utilities and independent power producers to charge ''market-based rates' for their wholesale services rather than cost-of-service rates established by regulators.[44] Under market-based pricing, wholesale power rates are not based on a detailed evaluation of costs of service plus an appropriate rate of return set by regulators, but rather on a price set through competitive bidding or arms-length negotiations between power sellers and purchasing utilities where market power is absent or mitigated. Some proponents expressed a preference for wholesale rates set by competitive market signals instead of regulators' projections, estimates, and judgments in the belief that such an approach would produce a more economically optimal result for society.[45] Others also argued pragmatically that market-based rates with prospects of higher profits than those available to regulated utilities were needed to attract new entrants, so-called independent power producers, to build new powerplants because the pace of utility construction had slowed and some feared an impending capacity shortfall.[46] Still others supported the availability of market-based prices and the expanded participation of independent power producers in generation markets to provide utilities with a greater variety of options in resource planning and acquisition.

While FERC generally retains cost-of-service rate policies for bulk power sales, in a growing number of cases, the commission has accepted market-based prices. By May 1993 FERC had received more than 40 applications for market prices for wholesale power contracts and had approved 29 of these requests and rejected 9.[47] In approving these transactions, FERC imposed various conditions intended to establish that the applicant's market power has been mitigated. The preconditions for receiving market-based rates have been evolving on a case-by-case basis and FERC has not adopted any generic policy. In these and other cases, FERC has used its conditioning power to require applicants to expand access to transmission services to provide wider

44 In 1987, FERC solicited public comments on three notices of proposed rulemakings (NOPRS): 1) competitive bidding for new power requirements, 2) determination of avoided costs under PURPA, and 3) treatment of independent power producers. See discussion in OTA, *Electric Power Wheeling and Dealing*, supra note 14, pp. 77-79. The FERC NOPRS proved controversial, and efforts to establish formal rules or policies were abandoned as commission membership changed. With the support of several commission members and key FERC staff, however, the overall policy goals were still pursued on a case-by-case basis. See Congressional Research Service, supra note 18, pp 170-172.

45 For more discussion and references for the various deregulation proposals, see Congressional Research Service, supra note 18, pp. 232-303.

46 J. Steven Herod and Jeffrey Skeer, "A Look at National and Regional Electric Supply Needs," paper presented at the 12th Energy Technology Conference and Exposition, March 1985; U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, Staff Report, "Electric Power Supply and Demand for the Contiguous United States, 1987-19%," DOE/E-0011 (Springfield, VA: National Technical Information Service, February 1988); "Summary of Current Staff Proposal on PURPA-Related Issues," Federal Energy Regulatory Commission Sept. 11, 1987. Other industry experts discount the shortfall theory, interpreting the slowdown as the natural result of aggressive overbuilding of large capacity baseload plants and slower economic growth. They also note that new capacity needs for many utilities are for smaller increments of peak-load power, which would be met by combustion turbines and other short-lead time resources.

47 Federal Energy Regulatory Commission Office of Economic policy, personal communication, June 2, 1993. One application is still pending and another was terminated for failure to respond to a deficiency finding.

opportunities for other buyers and sellers in bulk power markets.

TRANSMISSION ACCESS

Access to transmission services allows utilities opportunities to purchase and sell power in a wider area beyond their local host utilities and adjacent utilities. Within segments of the electric utility industry and regulators, there has been longstanding concern that some transmission "haves" might use their control over regional transmission systems to keep their wholesale utility customers captive and to deny competing wholesale power providers access to bulk power markets. Utilities that have been denied wheeling services have had only limited options.[48]

The extent of FERC'S authority to order one electric utility to transmit or "wheel" over its lines power produced by another generator has been a matter of contention for years. FERC'S authority under the original Federal Power Act to order wheeling was not explicit. PURPA, for the first time, provided explicit wheeling authority but placed such severe limitations on its exercise that made it all but impossible to obtain wheeling orders.[49] In recent years FERC has relied on its authority under other provisions of law to advance its policy goals of expanding access to transmission services to promote the growth of competitive bulk power markets. For example, FERC conditioned the approval of several large utility mergers on agreement that the merged utility system offer transmission services to other utilities.[50] FERC also has encouraged several utilities seeking acceptance of market-based rates for wholesale power transactions to file open-access transmission tariffs as a means of mitigating market power.

The Energy Policy Act of 1992 clarified and strengthened FERC'S wheeling authority .51 Now utilities, independent power producers, and others can apply to FERC for mandatory wheeling orders to carry out wholesale power transactions. This change provides new impetus for the growth of competitive power markets and expands the options available to utilities in resource planning and acquisitions. The act restricted retail wheeling—provision of transmisson services to retail customers--but left State authority in such matters untouched. With the basic question of whether FERC can issue wheeling orders settled, new controversies are likely to arise as FERC struggles to establish fair and workable policies on transmission pricing and capacity determinations.

ASSURING QUALITY OF SERVICE

Unlike State regulatory commissions, FERC has only very limited authority under the Federal

48 In *Otter Tail Power Co.* v. *United States*, 410 U.S. 366, at 375 (1973), the U.S. Supreme Court noted in dicta that the Federal Power Act did not grant any authority to order wheeling, but that wheeling could be ordered by the Federal Courts as a remedy under the antitrust laws. A similar conclusion on wheeling authority is reached in National Regulatory Research Institute *Non-Technical Impediments to Power Transfers*, September 1987, pp. 52-68, although the author notes that FERC may have some as-yet-untested authority to order wheeling as a remedy for anticompetitive behavior under sees. 205 and 206 of the Federal Power Act, id. at note 45, p. 64. See also *Florida Power & Light Co. v. FERC*, 660 F. 2d 668 (5th Cir. 1981), p. 679. The report of the Conference Committee on PURPA is vague on the extent of any existing wheeling authority FERC might have outside of sees. 211 and 212 and notes that PURPA is not intended to affect existing authority, House Conference Report 95-1750, to accompany H.R. 4018, 95th Cong., 2d sess., Oct. 10, 1978, pp. 91-95, *U.S. Code Congressional and Administrative News, 1978, pp. 7825-7829.*

49 PURPA, secs. 203 and 204, amended the Federal Power Act to add new sees. 211 and 212, 16 U.S.C. 824j and 16 U.S.C. 824k.

50 In *Re Utah power& Light co. et al.* (Oct. 26, 1988), FERC approved the merger of Utah Power & Light Co. into Pacific Power & Light Co., subject to the condition that the merged companies provide firm wholesale transmission services at cost-based rates to any utility that requested such service. The condition was necessary to prevent the future exercise of market power by the new company to foreclose access by competitors to bulk power markets. The decision was reached under sec. 203 of the Federal Power Act, which requires commission approval of mergers and acquisitions. A more expansive 'open access" provision was included in the FERC approval of Northeast Utilities acquisition of the bankrupt Public Service Co. of New Hampshire.

51 Public Law 102-486, Oct. 24, 1992, 106 Stat. 2776. Expanded transmission access provisions are contained in Title VIII, Subtitle B, secs. 721-726, 106 Stat. 2915-2921, which amend sees. 211 and 212 of the Federal Power Act.

Power Act to remedy inadequate service.[52] If a State commission fries a complaint, and if FERC finds that interstate service of a public utility is inadequate or insufficient, the commission can order the utility to provide the proper level of service provided that the utility has sufficient capacity available .53 The commission has no authority to compel a utility to enlarge its generating facilities or to sell or exchange electricity when doing so would impair its ability to render adequate service to its customers.

There is no Federal rate penalty for failure to provide adequate and reliable service under Federal law, nor is there a basis to provide more favorable treatment to utilities providing superior performance. Rate treatment provides no incentive or disincentive for performance or to remedy inadequate service.

Nevertheless, there is a chain of decisions creating a Federal obligation to provide wholesale service. FERC can require a jurisdictional utility to provide wholesale service to another utility where the ability of the purchasing utility to meet its customer needs is threatened and the selling jurisdictional utility can provide the service without imposing an undue burden on service to its own customers. This has come into play when long-term power purchase contracts have expired, and the parties have not entered into new arrangements, and protects the purchasing utility from being left without power supplies. If, however, generating capacity is not available, FERC cannot enforce wholesale contracts or the obligation to seine.

Adequacy and reliability have been dealt with as planning tools for electric utilities and not as matters of regulatory concern. PURPA amended the Federal Power Act to include provisions dealing with interconnections and emergency power sharing arrangements. Utilities are required to report anticipated power shortages to FERC and contingency plans to State regulators. FERC is authorized to work with State commissions and local reliability councils to promote reliability in utility planning and coordination activities. Beyond this, there are no explicit responsibilities.

ENERGY EFFICIENCY, RESOURCE PLANNING, AND DEMAND-SIDE MANAGEMENT

Compared to the scope and extent of State regulation of utility activities, FERC leaves largely untouched many areas related to energy efficiency and resource planning. This has been primarily a matter of policy, but also reflects uncertainty over the extent of FERC power and influence over generating resources and retail operations under the Federal Power Act.

FERC regulations and rate procedures are focused on the costs of service of the entity selling electric power and not on the purchasing utility. Its concepts of just and reasonable rates, and the obligation to provide electricity at the lowest possible rates consistent with adequate service, have not been expanded into requiring that either the selling or buying utility demonstrate that the resource selected is the lowest cost alternative for meeting customer needs, considering both supply and demand-side alternatives.

PUBLIC UTILITY HOLDING COMPANIES

Under PUHCA any company that owns or controls more than 10 percent of the voting securities of a public utility is considered to be a public utility holding company. An electric utility company is any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale. The holding companies are subject to extensive regulation of their financial activities and operations. Public utility holding companies that operate wholly within one State or in contiguous States

52 Congressional Research Service, *supra* note 18, p. 157.

5316 U.S.C. Section 824 f.

can qualify for an exemption from the most stringent regulatory oversight of PUHCA. Exemptions also apply to companies primarily engaged in nonutility business and not deriving a material part of their income from the public utility business.[54] Nonexempt entities are registered holding companies and are limited in their operations to "a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate [there]to. ' Integration means that the utility operations are limited to a single area or region of the country. Registered holding companies must obtain SEC approval of the sale and issuance of securities; transactions among their affiliates and subsidiaries; and services, sales, and construction contracts. In addition, the companies must fide extensive financial reports with the SEC. In contrast, exempt companies need only file limited annual reports with the SEC.

With the growth of wholesale power markets in the late 1980s, PUHCA requirements were criticized as unfairly restricting entry into the competitive power industry and requiring unnecessarily complex corporate structures for independent power projects. These so-called "PUHCA pretzels' ' were created to avoid the geographic restrictions on holding company operations and/or the loss of the PUHCA exemption for qualifying facilities under PURPA. Even so, the independent power sector grew substantially over the period and among its major players are the independent power affiliates of regulated electric utilities.

The Energy Policy Act of 1992 amended PUHCA to create a new category, the exempt wholesale generator (EWG), for certain entities either building or operating generating facilities that sell electricity at wholesale to electric utilities.[55] The act also loosened restrictions on involvement of domestic registered holding companies' affiliates in power markets outside the United States.

Regulation of resource planning and affiliate transactions by registered holding companies has been a recurring source of tension between State and Federal regulators.

■ State and Federal Conflicts

While States have exclusive retail rate jurisdiction, under the *Narragansett* doctrine they must generally pass through wholesale rates previously approved by FERC.[56] The extent to which prior FERC determinations of the reasonableness of wholesale rates preempts State consideration of the retail impacts of those same rates is a matter of some controversy.[57] The strain arises because State regulatory programs and the considerations used in setting rates are generally far more extensive than FERC'S. In some cases, requiring States to adopt without question FERC'S wholesale rate determinations in setting retail rates would preclude States from exercising their own regulatory authority over issues normally within their jurisdiction, such as resource planning and acquisition and facility siting.

The major limitation on Federal preemption is found in the *Pike County* exception, which affirmed the right of a State commission to examine the prudence of a wholesale power purchase contract and to disallow the pass-

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54 15 U.S.C. 79c.

55 Public Law 102-486, Oct. 24, 1992, 106 Stat. 2776.

56 This rule was set forth in *Narragansett Electric* Co. v. *Burke,* 119 R.I. 559,381 A.2d 1358 (1977), *cert. denied, 435* U.S. 972 (1978), one of a series of State court decisions that recognized Federal preemption.

57 For discussion of these issues, see the following: Ronald D. Jones, "Regulations of Interstate Electric Power: FERC Versus the States,' 2 *Natural Resources & Environment 3,* Spring 1987; Lynn N. Hargis, "The War Between The Rates Is Over, But Battles Rem@' 2 *Natural Resources & Environment 7,* Spring 1987; and Bill Clinton, Robert E. Johnston, Walter W. Nixon, III, and Sam Bratton, ''FERC, State Regulators and Public Utilities: A Tilted Balance?" 2 *Natural Resources & Environment* 11, Spring 1987.

through of FERC-approved wholesale costs if lower cost power supplies were available elsewhere.[58] The issue of whether States can review the prudence of wholesale power contracts will become especially critical if, as a result of State least-cost planning initiatives and competitive procurement practices, utilities rely more heavily on bulk power purchases for new power supplies. Wholesale prices for power sales from utilities and independent generators, except for QF transactions, fall exclusively within FERC'S jurisdiction, as do the terms and conditions for transmission services. This creates a situation where States shape the initial consideration and choice of resources for their jurisdictional utilities through the planning process but have diminished control over wholesale power costs. The split jurisdiction increases the potential for utilities to escape State jurisdiction at the same time that the growth of competitive power' entities, including unregulated utility independent power affiliates, raises State regulator concerns over their ability to effectively control self-dealing, unfair competition, and other unfair practices.

The vitality of the *Pike County* exception has been cast into doubt by the Supreme Court's 1988 decision in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore. In* this decision, the Court rejected State efforts to deny a rate increase based on FERC'S allocation of the costs of a nuclear unit built to meet the needs of an integrated interstate holding company system, on the grounds that the local subsidiary's participation in the project was imprudent.[59] The Court held that a State prudence inquiry was preempted even though FERC had not examined the issue during wholesale rate proceedings. The State regulators' only recourse is to challenge the prudence of the wholesale arrangements before FERC. Whether the *Mississippi Power & Light* decision is limited to the particular situation of interstate holding companies, or whether it marks further limitations on the powers of State regulators, is not yet known. Resolution of this controversy over conflicting Federal and State jurisdictional claims will be one of the major public policy issues in any transition to a more competitive electric power industry.

Note that the House and Senate versions of the Energy Policy Act of 1992 originally adopted different approaches to the Federal-State jurisdictional conflicts over competitive power transactions. Conferees failed to reach agreement on an alternative resolution, so the potential for conflict remains.

In an increasing number of cases, FERC'S efforts to expand competition in bulk power markets in pursuit of economic policies and streamlining g the bureaucratic process is moving Federal regulation away from detailed consideration of costs of service. At the same time, States though IRP, incentive rates, and DSM are moving toward greater oversight and involvement in utility planning and decisionmaking to promote least-cost energy plans. A number of State regulators see the potential for a clash between State least-cost plans and FERC (and SEC) preemptive regulation of wholesale transactions, particularly in the area of multistate utility holding companies. This has led to proposals for legislation to give States greater responsibility in resource planning areas, authorizing interstate plans for multistate utilities, and requiring FERC

[58] *pike County Light & power Co. v. Pennsylvania Public Utility Commission, 77* Pa. Comm'w. 268, 465 A. 2d 735 (1983). The potential exception was apparently accepted by FERC in *Pennsylvania Power & Light Co., 23* F. E.R.C. 61,005 (1983) and noted by the U.S. Supreme Court in *Nantahala Power & Light Co. v. Thornburg*, 106 U.S. *2349 (1986).*

[59] *Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487* U.S. 354, 108 S. Ct. 2428, 101 L. Ed 2d. 322 (1988.)

rulings **to be** consistent with State plans or at least involve consultations with State regulators.[60]

Other observers argue that such legislation is not needed because in their view the potential for conflicts is minimal and existing law could allow cooperation and consultation among FERC and affected State regulators and holding companies before IRP approval.[61] Some also see **the potential** for regional integrated resource planning decisions to result in some unspecfied adverse impacts on bulk power markets and access to transmission services.[62]

OVERVIEW OF ELECTRIC UTILITY SYSTEMS AND OPERATIONS

Electric utilities provide much more than the commodity of kilowatt-hours of electricity. Their special obligations as public utilities require them to assure reliable, adequate, safe, and economic electric service on demand to customers in their franchise area. Utility customers value electricity for the energy services that it provides (e.g., lighting, heating, cooling, machine drive). The evolving perception of the role of utilities as providers of reliable and economic energy services to customers rather than purveyors of kilowatt-hours is evidenced in shifts both in internal utility organization and in regulatory policies. These changes reflect recognition of the potential contribution of utility conservation, load management, and efficiency programs in reducing electricity demand growth as an effective means of servicing customer needs and as an alternative to new powerplant construction.

As part of their obligation to serve, electric utilities must anticipate and match customer demand, while assuring system reliability, minimizing electricity rates, and maintaining financial health. To do this effectively—and for privately held systems at a profit-requires highly complex physical systems, specialized personnel, a myriad of operations, and extensive planning capabilities. Figure 3-5 shows a simplified electric power system. The structure and operations of electric utilities in the United States are shaped by the physical requirements of running reliable interconnected electric power systems and by the special institutional requirements imposed by their regulated monopoly status and service territories.

In particular, many features of the design and operation of electric power systems reflect two fundamental physical principles of electricity:[63]

1. Electricity must be generated as it is needed because it flows at nearly the speed of light with virtually no storage of power in the system.

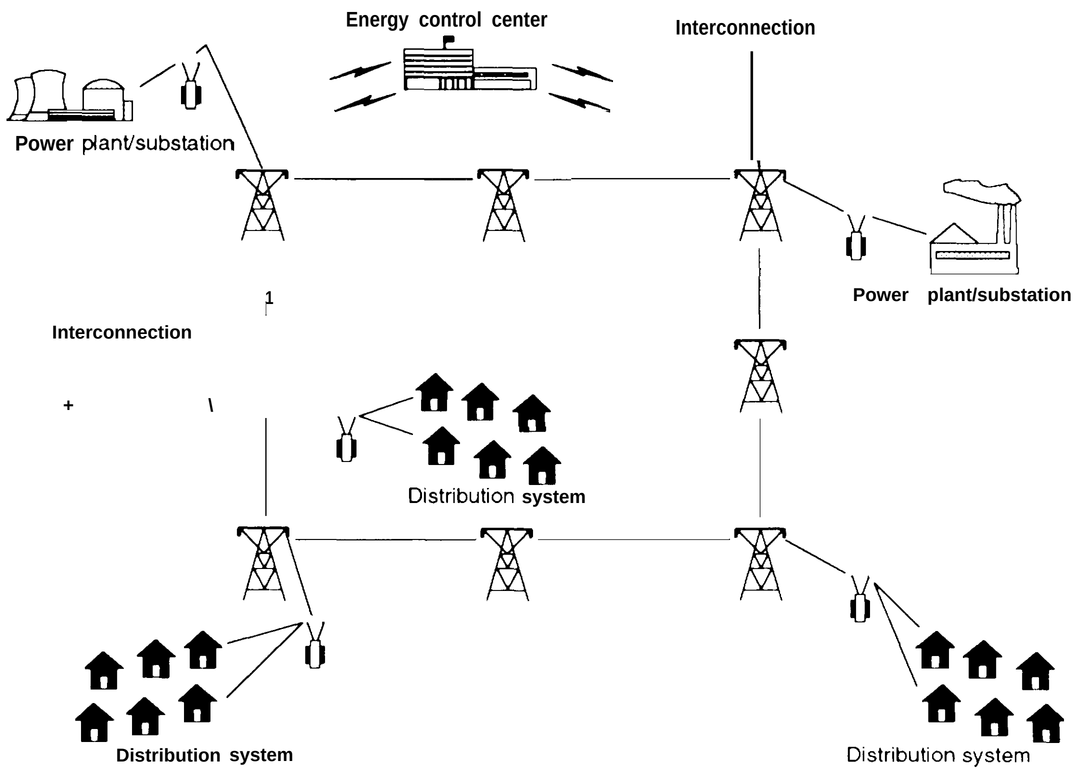
60 See, for example, Statement of Ashley C. Brown, Commissioner, Ohio Public Utilities Commission in Hearings on S. 2607, Legislation Authorizing Regional Integrated Resource Plarming before the Senate Committee on Energy and Natural Resources, May 14, 1992. Commissioner Brown, on behalf of the National Association of Regulatory Utility Commissioners, testified that as a result of Federal court rulings and FERC policies, ''under current law, holding company systems registered under PUHCA cannot be effectively regulated at any level of government—State, Federal, or local. " See also the Statement of Sam I. Bratton, Jr., Chairman, Arkansas Public Service Commission, Hearing on S. 2607 Before the Committee on Energy and Natural Resources, U.S. Senate, May 14,1992. Chairman Bratton testified that as a result of the U.S. Supreme Court decision in *Mississippi Power & Light v. State of Mississippi ex rel. Moore,* 487 U.S. 354 (1988), electric utility holding companies could avoid State regulatory review of retail rates by shifting generation from retail to wholesale subsidiaries. Bratton further observed that while commentators continued to debate the extent of the *Mississippi Power & Light* decision, ". . . participants in the debate seemed to agree on one thing: State regulators and registered holding companies cannot plan for additions of resources for their system and be assured that such plans will ultimately be overturned by FERC.'' He termed the situation "a major regulatory gap' and ''preemption without planning. " The State regulators were joined in their support of legislation on cooperative regional integrated resource planning by Entergy Corp., the registered holding company involved in the *Mississippi Power& Light case.*

61 See testimony of William S. Sherman, General Counsel, Federal Energy Regulatory Commission, before the Committee on Energy and Natural Resources, U.S. Senate, May 14, 1992.

62 Ibid.

63 For a more detailed treatment of utility operations and **planning,** see ch. 4 in OTA, *Electric Power Wheeling and Dealing,* supra note 14, from which this discussion was drawn.

Figure 3-5 Simplified Model of an Electric Power System



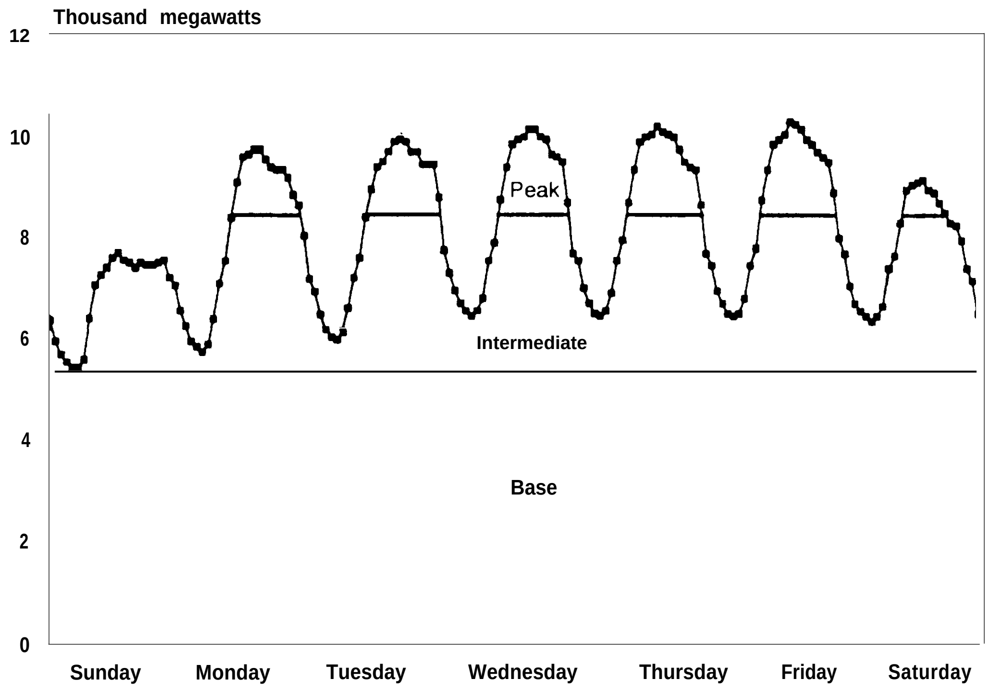
SOURCE: U.S. Congress, Office of Technology Assessment, Electric *Power Wheeling* and *Dealing: Technological Opportunities for Increasing* Competition, OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989), p. 11.

2. Every flow of electricity from a powerplant to a distribution system affects the entire transmission system, not just the most direct path between them.

The first principle means that electric power systems must be planned and operated to follow customer demand (load) instantaneously. Following load requires that if customer demand for electricity increases, more generating units must be dispatched to meet the increase in load, and when load decreases, generation must also be backed down. Customer demands on the system change continuously, although they exhibit daily, weekly, and seasonal load cycles. Figure 3-6 shows a weekly load profile for a typical utility. Sudden failure of generating units or transmission components instantly affects frequency and voltage across the power system. Following load requires that utilities forecast likely patterns of customer demand and possible equipment failures and plan for and maintain adequate generating resources and transmission capacity in reserve and readily available to meet changes in demand and respond to contingencies on short notice. Moreover, power systems must be operated at all times to maintain narrow frequency and voltage standards to protect customer and power system equipment and to preserve system stability.

The second principle means that power transmission affects not only the transmission lines of the utility generating the power but also all the transmission lines of utility systems interconnected with it. When one utility transfers power to another utility, the receiving utility reduces its

Figure 3-6-Weekly Load Curve



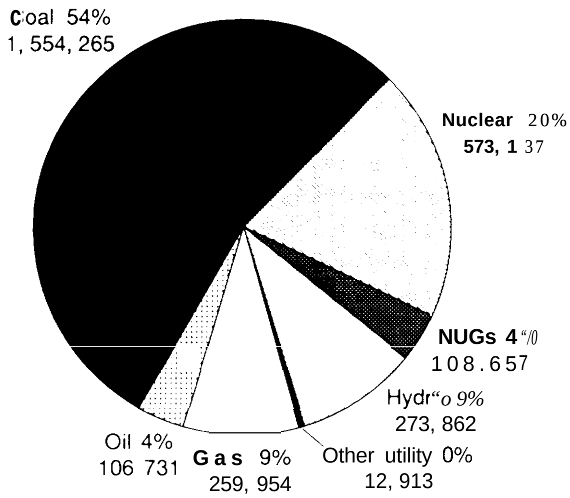
SOURCE: Office of Technology Assessment, 1883, based on Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non-Utility Generation," contractor report prepared for the Office of Technology Assessment, March 1988, pp. 2-3.

generation while the selling utility increases its generation, but the power flows over all paths available, not just the transmission lines of the two utilities involved. Part of the load may be carried by the transmission lines of other utilities hundreds of miles away, reducing the amount of power that those utilities can place on their own lines and, perhaps, overburdening a fully loaded line, and thus risking failure. Therefore, to maintain the integrity of the grid, each utility must control its operations and coordinate its transactions with neighboring systems to ensure that no components are overloaded on any of the possible paths available.

In addition to satisfying basic physical conditions, utilities must meet certain operational requirements. They must design and operate their systems to provide electricity with the correct frequency and proper voltage for customer equipment. The service must be reliable-sufficient to meet changing customer loads with an acceptable level of outages or service interruptions. In practice, voltage, frequency, and reliability are viewed as fundamental technical performance standards that must be met in system operation and planning. Plannin g and operating the power system in a manner that minimizes costs to the customer and maintains the profitability of the utility enterprise are additional objectives for utility decisionmakers and their regulatory overseers.

Satisfying these technical and operating conditions over seconds, hours, days, months, and years requires a high degree of coordination, planning, and cooperation among utilities, and detailed data and engineering analyses. This section reviews the major components of electric power systems infrastructure and operation and planning functions.

Figure 3-7—Electricity Generation by Fuel 1990 (millions of kWh)



SOURCE: Office of Technology Assessment, 1993, based on data from the North American Electric Reliability Council.

■ Electric Power System Components

The physical infrastructure of an electric power system consists of:

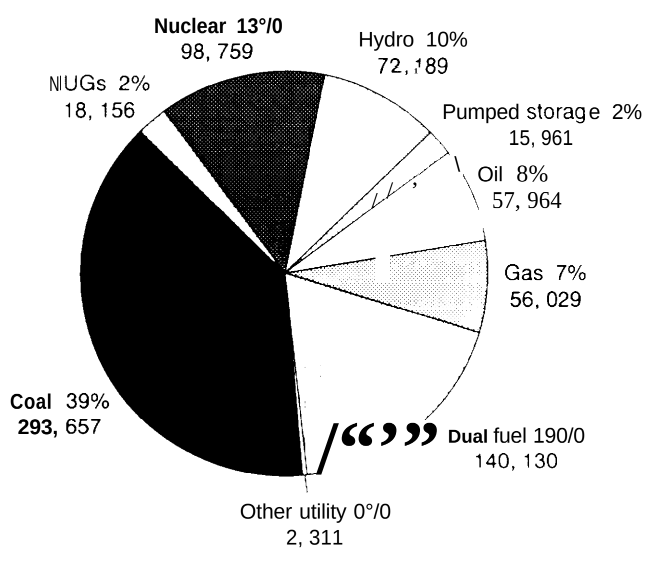
- generating units that produce electricity;
- transmission lines that transport electricity over long distances;
- distribution lines that deliver the electricity to customers;
- substations that connect the pieces to each other; and
- energy control centers to coordinate the operation of the components from moment to moment and in the near future.

A wide variety of other planning and engineering systems coordinate capacity utilization and expansion plans for the longer term. Figure 3-5 shows a simple electric system with two powerplants and three distribution systems connected by a transmission network of four transmission lines and is linked with neighboring utility systems by two tie lines.

Electric generators convert mechanical energy derived from fossil fuel combustion, nuclear fission, falling water, wind, and other primary energy sources to produce electricity. Utilities often have a mix of generating units that run on different energy sources and that are suitable for base, intermediate, or peaking loads. As shown in figure 3-7, about 56 percent of electricity generated in the United States in 1990 came from coal-fired generation and another 21 percent came from nuclear units. Installed generating capacity by fuel source is shown in figure 3-8.

Generators typically produce alternating-current (AC) electricity at a frequency of 60 cycles per second (60 Hertz or 60 Hz) with voltages between 12,000 and 30,000 volts. The frequency of all generating units on a system must be precisely synchronized. Automatic voltage regulators on generating units control the unit's voltage output, and speed governors monitor frequency and adjust power output in response to changing system conditions to maintain balance.

Figure 3-8—Electric Utilities Installed Generating Capacity 1990 (summer megawatts)



SOURCE: Office of Technology Assessment, 1993, based on data from the North American Electric Reliability Council.

A powerplant consists of one or more generating units on a site together with a generation substation that connects the generators to transmission lines. Power transformers at the substations raise the voltage to higher levels for efficient transmission. Substations also hold monitoring and communications equipment and control and protective devices for transmission and generation facilities.

Transmission lines carry electric energy from the powerplants to the distribution systems. To minimize losses over long distances, transmission lines operate at high voltages, typically between 69 and 765 kilovolts (kV). Most transmission in the United States consists of overhead AC lines, but direct current (DC) transmission lines and underground cables are used for special applications. Power transformers raise the generator voltage to the transmission voltage and back down to the distribution network level (typically under 35 kV) at the other end.

Transmission systems consist of interconnected transmission lines (the conductors (e.g., wires) and their supporting towers) plus monitoring, control, and protective equipment and devices housed in transmission substations and used to regulate voltage and power flow on the lines.

Most customers receive their electricity from a distribution system.[64] 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.

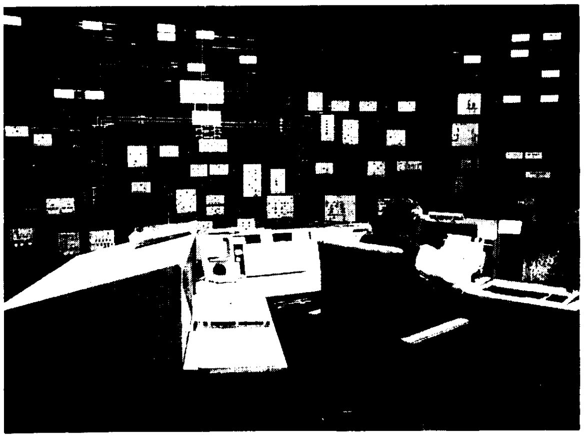
The distribution system is divided into the primary distribution system, operating at between 2.4 and 35 kV, which moves power short distances and serves some moderately large industrial and commercial customers, and the secondary distribution system at 110 to 600 volts, which typically serves groups of customers in neighborhoods. The primary distribution system delivers power to distribution transformers, which reduce voltage to the secondary system voltage levels.

Protective apparatus in the distribution system includes 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 is usually done manually by dispatching a work crew to the site.

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. The energy control center coordinates the operation and dispatch of all power system components within a defined geographic region called a control area. One or more utilities may make up a control area. The control area in figure 3-5 is interconnected to two neighboring control areas through transmission lines. There are approximately 160 individual control areas in the United States.

Energy control centers use a variety of equipment and procedures: monitoring and communication equipment (telemetry) to keep constant watch on 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 that actually control generators and transmission lines. The control center equipment and procedures are typically organized into three somewhat overlapping systems:

64 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 connects these large customers to a transmission line.


CASAZZA, SCHULTZ & ASSOCIATES, INC.

Utilities monitor and direct power system operations within a control area from the energy control center show here.

1. automatic generation control (AGC) systems, which coordinate the power output of generators to balance supply with customer demand;
2. supervisory control and data acquisition (SCADA) systems, which coordinate the transmission line equipment and generator voltages; and
3. analytical systems, which monitor and evaluate system security and performance, and plan operations.

These three systems are sometimes integrated in a full energy management system (EMS).

Sophisticated coordinated operation and planning systems control the vast complex of generators, transmission lines, distribution systems, and substations that makes up the typical electric power system. Coordination operation systems include monitoring and communication equipment, devices that actually control generators and transmission lines, and engineering models and expertise that together specify how to operate generators and transmission lines. Planning systems focus on the selection of the technology requirements (generation, transmission, distribution, and energy conservation/efficiency resources and operating and maintenance practices) to satisfy predicted demand in an economic manner. Planning functions operate on several time horizons-from daily, weekly, or seasonal scheduling commitment of generation and transmission resources to long-term, 20- to 40-year system capacity expansion and maintenance plans. Integrated resource planning is one planning mechanism used to carry out utility intermediate and long-term strategic planning functions.

Backing the coordinated operation and planning systems are advanced software and engineering models, experienced technical personnel, and a host of engineering and technical standards and other institutional arrangements that together assure the safe, reliable, and economic operation of electric power systems and coordinate operations with other interconnected utilities. Carrying out these various operations requires detailed and extensive information on utility systems, load characteristics, and customer needs.

Operating and Planning Functions

Together the coordinated operating and planning systems and procedures aid utilities in the performance of three general functions: following changing loads; maintaining reliability; and coordinating power transactions.

In practice, utilities seek to perform these functions at minimum cost. Each of these basic functions focuses on different time horizons and different aspects of the power system. See table 3-3. Some procedures are performed continuously, such as coordinating the energy output of generating units to balance demand. Others, such as planning generation additions and DSM programs, are performed far less often. Each time horizon beyond a few seconds requires forecasts of customer demand and performance of system equipment. All require a tremendous amount of information, computing power, and communication capability, as well as extensive coordination within and among the various organizations involved.

Table 3-3-Electric Utility Operating and Planning Functions

Function	Purpose	Procedures Involved
Following load		
Frequency regulation	Following moment-to-moment 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		
Security	Preparing for unplanned equipment failure.	Unit commitment (for spinning and ready reserves). Security constrained dispatch. Voltage control.
Adequacy	Acquiring adequate supply and DSM resources to meet demand.	Unit commmitment. Maintenance scheduling. integrated resource planning for supply and DSM.
Coordinating transactions	Buying, sailing, and wheeing power in interconnected systems.	AGC/economic dispatch. Unit commitment.

SOURCE: Office of Technology Assessment, 1993.

FOLLOWING LOAD

The ability to follow load is central to the operations of utility systems. Following load requires that at each moment the supply of power must equal the demand of consumers and that utilities maintain power frequency and voltages within appropriate limits across the utility system. Consumer demand for electricity changes continuously and somewhat unpredictably. Some load changes tend to repeat cyclically with the time of day, day of week, and the season. Others result from the vagaries of weather, economic conditions, and from the random turning on and off of appliances and industrial equipment. Because these load patterns cannot be forecasted accurately, utilities must plan for and secure generating, transmission, DSM, and control resources to meet a variety of future customer load patterns over the short, medium, and long term. Utilities rely on unit commitment schedules, economic dispatch, and automatic and operator control of generation to follow loads while maintaining frequency and voltage.

Utilities establish detailed unit commitment plans to ensure a sufficient supply of generation to follow loads and to provide backup power supplies for immediate operation in case of contingencies such as failure of a generating unit or transmission line. The schedules are based on forecasted load changes over daily, weekly, and seasonal cycles plus an allowance for random variations and equipment outages.

Unit commitment schedules specify which units Will be warmed up and cooled down to follow the load cycles and to provide spinning reserves.[65] Some generators in a unit commitment schedule increase or decrease their power output according to a schedule, following predicted loads; others are under AGC and economic dispatch to follow actual loads as required. Power

65 Spinning reserves are generating units that are operating and synchronized with the power grid and ready to send power to the system instantaneously to meet additional demand or respond to outages.

purchases from other utilities are also specified. The unit commitment plan ensures that sufficient generation under governor control is available for regulating frequency in response to changing loads. Voltage control and reactive power devices on the transmission system and in generating plants are simultaneously coordinated to maintain system voltages as loads and supplies change.

Utilities calculate unit commitment schedules to minimize the total expected costs of power generation and maintaining spinning reserves for reliability and to meet expected changes in demand. 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 costs and 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 warmup 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.

Maintaining Frequency

The design of customer equipment such as motors, clocks, and electronics often assumes a relatively constant power frequency of 60 Hz for proper operation. 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. Power system equipment is more sensitive to frequency deviations than consumer equipment and the control systems of modem power systems function by monitoring slight frequency deviations and responding to them.

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. Speed governors on most generating units constantly monitor frequency and regulate those units' power output to help balance demand and restore the frequency.

The usefulness of a particular generator in regulating frequency varies from unit to unit because of differences in the vamp rate-the rate at which generator's power output can increase or decrease. Large steam generating units such as nuclear powerplants and large coal units generally change output levels slowly, while gas turbines and hydro units are very responsive. Power system operators and planners must consider the responsiveness and availability of generators to control frequencies in setting unit commitment schedules and planning new supply resources.

Controlling Voltage

Many types of customer equipment require voltage to fall within a narrow range to function properly. For example, if delivered power voltage is too low, electric lights dim, and electric motors function poorly and may overheat. Overly high voltages, on the other hand, shorten the lives of lamps substantially and increase motor power, which may, damage attached equipment.

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.

Maintaining voltage involves balancing the supply and demand of **reactive** power in the system. Reactive power is created when current and voltage in an alternating current system are not in phase due to interactions with electric and magnetic fields around circuit components.[66] Reactive power is often referred to as VARS (for volt amperes reactive).

Maintaining voltages within the standards required by system equipment is the function of VAR control systems which monitor voltages and adjust generation and transmission system components accordingly. Monitoring equipment at various locations in the system measures and telemeters voltages to the energy control center where voltage levels are checked to ensure they fall within the acceptable range. When voltages begin to deviate from the acceptable limits, both automatic and remotely controlled actions are taken using a variety of reactive power control devices. Supervisory control and data acquisition systems combine telemetry of voltage to the control center and remote control of VAR supplies.

Reactive power is regulated by adjusting magnetic fields within the generators either automatically or under the control of system operators. 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.

Plannin g and selecting generation and transmission resources and designing coordination and control systems must build in consideration of reactive power flows and VAR control to keep the system operating at the proper voltage.

Economic Dispatch

Economic dispatch is the coordinated operation of generating units based on the incremental costs of generation and is a key to minimizing cost. The incremental production cost of a generating unit is the additional cost per kilowatt-hour of generating an additional quantity of energy or the cost reduction per kilowatt-hour 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, consistent with system security requirements. Typically, economic dispatch is entirely recomputed every 5 to 10 minutes at the control area.

Automatic Generation Control

The dispatch of generators in a control area is handled by computerized AGC systems that calculate increases or decreases in each generating unit's output required to maintain the balance between supply and demand in the least costly way. AGC gives utilities the capability of controlling system operations for economic dispatch, load following, reliability, and coordinating transfers. An AGC system constantly monitors the power system frequency to determine whether increased or decreased output is required and automatically resets generator governors to maintain frequency. AGC systems also monitor and reset dispatch to use low-cost generating units to displace more expensive generation to the extent feasible given the availability of adequate trans-

66 In an alternating current system, voltage (electrical potential or pressure) and current (the number and velocity of electrons flowing) vary sinusoidally over time with a frequency of 60 cycles per second. The current and voltage, however are not necessarily in phase with each other-i. e., reaching the maximum at precisely the same time. Real or active power results from current and voltage in phase with each other, is measured in watts, and 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 not in phase as the result of the interaction of real power flows with the electric and magnetic fields created around circuit components. When voltage and current are in phase with each other over a transmission line, there is no net flow of reactive power. An imbalance in the supply and demand of reactive power or 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.

mission capacity and system security (reliability) criteria. AGC systems control both the planned and inadvertent power exchange between control areas. The AGC system typically resets generator governors every 5 to 10 seconds based on an approximation of economic dispatch.

To perform effectively, an economic dispatch and AGC system needs detailed cost and performance information (unit efficiency, dispatchability, capacity utilization, contract rates and terms) about each of the power system's operable generating units. The economic dispatch-AGC system also must take account of possible transmission line losses, and the adequacy and availability of transmission capacity to transfer power within voltage and load flow limits in determining the order of dispatch.

The extent of generation dispatchable under AGC systems is another factor that utilities consider in scheduling unit commitment and in planning new resource additions.

MAINTAINING RELIABILITY

Reliability is a measure of the ongoing ability of a power system to avoid outages and continue to supply electricity at the appropriate frequency and voltage to customers. To preserve reliability, utilities must plan for and maintain sufficient capacity or power supply arrangements to cover unscheduled outages, equipment failures, operating constraints for generating units, powerlines and distribution systems, coordinating maintenance scheduling, and addition of new resources and growth in customer demand. There are two aspects of reliability-security and adequacy.

Preparing for continued operation of the bulk power supply after sudden system disturbances and equipment failures is called maintaining security.[67] Bulk system outages occur when generation and transmission are insufficient to meet total customer demand at any instant, such as when a lightning strike on a transmission line or sudden equipment failure suddenly reduces the availability of a critical generator or transmission line. Bulk system failures account for a relatively small portion of customer service outages—around 20 percent. Distribution system problems, often from storm damage to distribution lines, are the source of most power outages experienced by customers. Security is maintained by providing reserve capacity of both generation and transmission in unit commitment schedules and security-constrained dispatch. The order of economic dispatch will be overridden if the dispatch scheme would threaten system security. Together with the coordinated engineering of relays and circuit breakers used to isolate failed or overloaded components, they ensure that no single failure will result in cascading outages.

The second major element of reliability is maintaining adequacy, which is the ability of the bulk power system to meet the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. Maintaining adequacy requires utilities to plan for and operate their systems to accommodate a number of uncertainties and constraints on system availability. The major uncertainties that utilities must develop contingencies for include: the cost and availability of fuels, future operating costs for generating units, construction cost and schedules for new equipment, and the demand for power. 'Technical constraints on system availability that must be addressed to preserve adequacy include: unit commitment schedules and economic dispatch for load following and security requirements, scheduling maintenance requirements for system components, and transmission and distribution system capabilities.

Planning new generation and transmission capacity involves selecting the right mix and location of both generation and transmission to meet the needs of following load and maintaining

67 As defined by the North American Electric Reliability Council (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. "

reliability under a variety of possible futures. In selecting an appropriate resource mix to meet customer needs, system planners are supposed to balance the value to the customer of having reliable service with minimal outages and the costs to the utility of providing this service. However, deriving quantitative estimates of the value of various levels of reliability to the customer and the costs to the utility of avoiding outages under a variety of conditions has proven difficult and intractable. Therefore, in practice, engineering planners assume a variety of rules of thumb or de facto reliability standards in system planning and operations. Three of the most common reliability-related goals are:

1. loss of load probability (LOLP) of 1 day in 10 years,
2. first (or second) contingency security, and
3. reserve margins of 15 to 20 percent. (See box 3-B.)

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. The choice of which standard to use is a matter of experience and engineering judgment as well as system-specific characteristics for individual utilities.

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 (such as generator or transmission failures) occur. Defensive operating practices entail holding generating units and transmission capability in reserve for the possible occurrence of a major failure in the system. 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.

Emergency Operations

Reliability operations and planning also entails establishing procedures for 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 frenquencies 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, and must be taken into account in unit commitment schedules and resource planning.

COORDINATING TRANSACTIONS

The third major function of coordinated operating and planning systems is to carry out power transactions. Interutility transactions 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 powerplants; and wheeling of power. Coordinating transactions involves scheduling and controlling generation and transmission to carry out the power transfers, as well as monitoring and recording transactions for billing or other compensation. Coordination

Box 3-B-Common Reliability Standards

Loss of load probability (LOLP) is a measure of the long-term expectation that a utility will be unable to meet customer demand based on engineering analyses. 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 10-year period.

Contingency security criteria means that sufficient reserves of transmission and generation are immediately available so that the power system will continue to operate in the event that the one (or two) most critical components fail. Usually the critical components are the largest generators or transmission lines, or some component at a critical location in the network. The reliability criterion applies at all times, even when some elements are already out of service. The criteria are established based on contingency studies and rely on engineering judgment to decide which types of failures are reasonable or credible.

Reserve margin is the difference between generating capacity and peak load expressed as a percentage of peak load and is the oldest and most traditional measure of reliability.[1] For example, in a system with a peak load of 4,000 MW and installed capacity of 5,000 MW, the reserve margin is calculated as follows:

(5,000 - 4,000) (divided by) 4,000 - 0.25, or 25%.

Reserve margins of about 15 to 20 percent typically have been considered sufficient to allow for maintenance and unscheduled outages. However, the appropriate reserve margin to assure reliability is determined based 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.[2]

[1] The North American Electric Reliability Council uses a similar measure called *capacity margin*, defined as the difference between capacity and peak load expressed as a percentage of capacity (rather than peak load). Because it uses a larger denominator, the capacity margin Is always smaller than reserve margins by a few percentage points. In practice, however, most utilities refer to their reserve margins. Capacity margins of 13 to 17 percent are commmonly considered acceptable.

[2] North American Electrlc Reliability Council (NERC), Reliability Concepts (Princeton, NJ: February 1985), p. 16.

may involve parties to the power transaction and third-party utilities that may be affected.

Interutility Coordination and Cooperation

The simple model of an electric utility system like that in figure 3-5 is of a stand-alone integrated utility that serves its own needs within an exclusive, geographically compact retail service franchise area. The model utility generates sufficient electric power from its plants to meet customer demand and delivers it via its own transmission and distribution systems to its customers. It exercises sole control over the operation and planning of all its system components and derives its profits from retail power sales and the return on capital investment in its rate base. It operates under the oversight of a single State ratemaking authority. The modern-day reality of electric utility systems, however, is far more complex.

Nearly all U.S. utilities operate as part of an interconnected regional grid and not as isolated systems. All these interconnected systems are multistate operations with the exception of Alaska, Hawaii, and utilities within the Electric Reliability Council of Texas (ERCOT). The transmission interconnections improve electric system reliability by allowing utilities to share generating and transmission resources, provide backup power supplies at peak loads and during emergencies, and engage in other bulk power transactions. While clearly conferring benefits, these interconnections also impose physical and legal constraints on utility systems. Utility operations and planning require a high degree of cooperation and communications among utilities on the system, and must satisfy technical performance standards and other formal and informal obligations imposed through control area and interconnections agreements, power pools, reliability councils, and various contractual arrangements for bulk power transfers.

Each utility is responsible for providing the power used by its customers without taking power from neighbors, unless alternate arrangements have specifically been made. Many utilities depend on wholesale purchases of electricity from other utilities or public power agencies or independent power producers for some or all of their power requirements. Utilities rely on wholesale transactions because they do not have enough generating capacity to meet the needs of their customers and/or because lower-cost power is available from others. Indeed, there are a large number of small municipal systems dependent on regional investor-owned or public power systems for their electricity supplies and transmission services. Many large investor-owned utility systems support generation and transmission facilities not only to serve their own retail distribution customers, but also to meet the long-term obligations to wholesale customers within their service areas, and to engage in short- or long-term wholesale power transactions with other utilities.

There are significant variations among utilities in different regions, and among utilities in the same region, that help shape planning and operations decisionmaking and regulatory policy. These include differences in industry structure, composition, and resource base characteristics that are traceable to patterns of population, climate, economic activity, and the history of electrification within each region. Among utilities, differences in generation reserve margins, fuel mix, load growth and coordination, and access to regional transmission systems will further shape power markets and resource options.

The structure of the electric power industry has been changing over the past decade as utilities have merged, reorganized into (exempt) holding company structures, and diversified into regulated and nonregulated ventures. One result of this diversification and corporate reorganization among investor-owned utilities is that traditional electric utility operations are no longer the only (or most profitable) source of corporate income. In some cases, the regulated public utility subsidiary serving retail distribution customers could find itself in competition with, or purchasing from, unregulated independent power and energy services subsidiaries or joint ventures of its parent holding company. These changes are introducing subtle and not so subtle influences into corporate decisionmaking--how will company officers and directors decide between providing for long-term, least-cost resources for the regulated electric utility and pursuing potentially higher returns on unregulated ventures. The changes create new challenges for utility regulators in policing the potential for self-dealing and cross-subsidization of unregulated ventures by utility ratepayers and, in many cases, transfer the regulatory venue from State to Federal jurisdiction.

The picture is further complicated by the growing presence of independent power producers and energy service companies as competitors with, and suppliers to, regulated electric utilities. These unregulated entities operate under different financial and regulatory regimes than traditional integrated utilities, and it remains to be seen if existing resource planning and regulatory approaches will be adequate to secure reliable and reasonably priced resources from these new entrants over the longer term.

The growing split in jurisdiction over electric utilities among States and between States and the Federal Government will undoubtedly influence resource decisions by individual utilities and by regulators. Greater reliance on bulk power transactions in utility resource plans will mean that

Federal regulators will have a more dominant role in determining electricity costs and that State regulators' control over utility costs, and ultimately retail electricity prices (rates), will be diminished.

As a result of these various influences, each utility system has a unique set of operational, structural, regulatory, and geographic conditions that drive its investment decisions and opportunities for enhancing energy efficiency. This diversity precludes easy generalizations and one-size-fits-all policy prescriptions for utility energy efficiency. Nevertheless, most utilities generally adhere to similar goals, performance standards, and operating and planning functions and procedures.