Chapter 6

Regional Characteristics of the Electric Power Industry

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INTRODUCTION

The electric power industry in the United States is a diverse and complex patchwork of investor- and consumer-owned utilities, government agencies, cogenerators, self-generators, and independent power producers. Regional differences in industry composition, structure, and resource base characteristics are in large part attributable to patterns in population, climate, economic activities, and the history of electrification in each region. These variations can influence the outcome of any initiatives to expand transmission access and to inject more competitive pressures into the generation market. Differences in generation reserve margins, fuel mix, load growth, and coordination among regions will be important in encouraging or discouraging the participation of outside or nontraditional power generators in competitive markets.

This chapter begins with an overview of the structure and regional divisions of the electric power industry. Next, it provides an overview of regional differences, including, for example, demand growth rates, capacity margins, capital spending, electricity prices, and nonutility generation potential. Key regional issues and determinants for increasing competition in the electric utility industry and some of the anticipated regional impacts of implementing OTA's scenarios are also discussed. The chapter concludes with a detailed summary of the characteristics of the industry in each of the nine regional councils of the North American Electric Reliability Council, including, for example, generation and transmission capacity, fuel use, projected demand (load) growth, and reliability concerns.

NERC REGIONS

The electric power industry is subdivided by reliability council regions, by interconnections, by control areas and power pools, and by utility. This section will focus on the reliability council regions. Chapter 2 provides an overview of industry control areas, power pools. and interconnections.

The North-American Electric Reliability Council (NERC) and its regional councils were established in the late 1960s to assist utilities in providing for the reliability and adequacy of electric generation, transmission, and distribution systems. Formation of the organizations was aided by Federal legislation following the Northeast blackout of 1965. NERC is a major source of information about electric utilities' generation and transmission capacity and utilization.

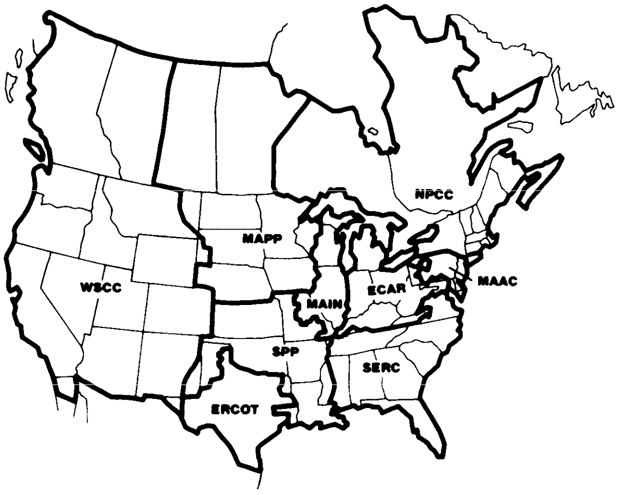
Within the NERC federation there are nine regional reliability councils covering the Continental United States, Canada, and portions of Mexico as shown in figure 6-1. The Alaska Systems Coordinating Council is an affiliate member of NERC, Hawaii's utilities are not participants in NERC. See table 6-1 for council membership and subregions. Table 6-2 summarizes key operating and financial characteristics of NERC regions. The boundaries of NERC regions are established by the extent of the service territories of member utilities. [1] Operationally, six NERC regions are further divided into subregions shown in figure 6-2.

The regional councils coordinate planning and operations and exchange information on electricity supply, demand, and reliability. The councils provide NERC with annual and seasonal assessments of electricity supply and the factors affecting adequacy, reliability, and security.

Membership in NERC regional councils is voluntary and eligibility criteria are set by each region. Sometimes, membership (and benefits) is not available equally to all utilities within a region. Most of the regions limit full voting membership to utilities that own generation or transmission and that can have a significant impact on regional operations; there are often additional qualifications. For example, the Southwest Power Pool (SPP) requires a minimum generating capacity of 300 MW for full

[1] Before 1987, regional boundaries and membership were determined by where the generating plants were located with the result that some utilities with widely dispersed operations, load centers, and generating plants could belong to several regions.

Figure **6-l-North American Electric Reliability Council**



ECAR: East Central Area Reliability Coordination Agreement
ERCOT: Electric Reliability Council of Texas
MAAC: Mid-Atlantic Area Council
MAIN: Mid-American Interconnected Network
MAPP: Mid-Continent Area Power Pool
NPCC: Northeast Power Coordinating Council
SERC: Southeastern Electric Reliability Council
SPP: Southwest Power Pool
WSCC: Western Systems Coordinating Council

SOURCE: North American Electric Reliability Council, Copyright © 1988.

voting membership.[2] The Southeastern Electric Reliability Council (SERC) has a minimum generating size of 25 MW for voting members. Voting strength is often apportioned according to the relative loads of member systems with larger systems having proportionately greater influence over regional decisions than smaller systems. Participation in regional activities is usually available on a nonvoting basis to nonqualifying utilities either directly as associate members or indirectly through representation.

Two regions also function as power pools: the Mid-Atlantic Area Council (MAAC) and the Mid-Continent Area Power Pool (MAPP). Regional council/pool members agree to coordinate planning and operations, maintain adequate reserves, and provide certain transmission services for other members. For example, MAPP requires members to maintain a reserve margin of 15 percent. MAAC voting membership is coextensive with membership in the centrally dispatched Pennsylvania-New Jersey-Maryland Interconnection (PJM).

Over *95* percent of the generating capacity in the contiguous United States is owned by utilities associated with NERC-either as full voting members of reliability councils, as associate members of reliability councils, or as cooperating utilities. NERC's voluntary operating standards and guidelines thus have a substantial influence over system requirements and operating conditions and over determinations of transmission capacity availability.[3]

Regional councils are highly individualistic in establishing reliability and operating criteria and in collecting and dispersing information. Some regions require adherence to their own reliability and operating criteria and impose penalties for those who fall short of these obligations.[4]

INDUSTRY OWNERSHIP AND STRUCTURE

The electric power industry in the United States includes electric utilities, independent power producers, cogenerators, and self-generators. Within the utility sector there are some 200 investor-owned utilities; 2,000 publicly owned State, municipal, county, district, or joint action agency utilities; 900 consumer-owned cooperatives; 5 Federal power marketing agencies; and the Tennessee Valley Authority.[5]

Regional ownership statistics in table 6-3 reflect the very different market shares of private and public

[2] Information from the North American Electric Reliability Council 1987 Annual Report; and "Summary of Responses of the Regional Reliability Councils to the National Governors' Association Survey on Electric Transmission Coordination and Planning. " OTA Contractor Report, Ohio Public Utilities Commission, Mar. 28, 1988 (hereafter "Reliability Council Survey Responses,")

[3] The role of utility or regional reliability standards in transmission capacity limits is discussed more extensively in chs. 4 and 5.

[4] See statements of individual regional membership qualifications in "Reliability Council Survey Responses," supra note 2.

[5] Complete and *accurate* information on the number of generators in the nontraditional or nonutility sector, their capacity, fuel use, and generation is not centrally available through the Energy Information Administration or industry sources.

Table 6-1—U.S. Membership of North American Electric Reliability Council Regions

NERC region	States	Member systems	Area served (square miles)	Population served
ECAR—East Central Area Reliability Coordination Agreement	MI, OH, WV,IN Most of KY and parts of VA, MD,PA	18 members 16 IOUS 2 Cooperatives	194,000	36 million
ERCOT—Ebctric Reliability Council of Texas	Most of TX	76 Members 6 IOUS 49 Cooperatives 20 Municlpals 1 State agency	195,000	11 million
MAAC-Mid-Atlantic Area Council	DE, NJ, PA, DC, and parts of MD& VA	11 Members (all IOUs) 5 associates (representing group of cooperatives)	48,700	21.1 million
MAIN—Mid-American interconnected Network	IL, and parts of MO, MI, and WI	13 Members 11 IOUs 1 Cooperative 1 Municipal 1 Associate	170,000	18 million
MAPP—Mid-ContinentArea Power Pool	IA, MN, NB,ND, and parts of WI, SD, MT, MI,IL	27 Participants 11 IOUs 8 G&T Cooperatives 4 Municipal 3 Public power districts 1 Federal agency 16 Associates	420,000 (U. S.)	13.6 million
NPCC--Power COordinating Council	CT, ME, MA, NH, NY, RI,VT	18 Full members 17 IOUs 1 State authority	112,527	27.4 million
SERC—Southeastern Electric Reliability Council	AL, FL, GA, NC, SC, TN, and parts of VA, MS, and KY	28 Member systems 16 IOUs 8 Municipals/public 2 Cooperatives 2 Federal agencies 8 Associates	345,650	25 million
SPP—Southwest PowerPool	AR, OK, KS, LA, and parts of MS, MO, TX, and NM	41 Systems 17IOUs 12 Municipal 8 Cooperatives 4 Government agencies	500,000	25+ million
WSCC—W@stern Systems Coordinating Council	AZ,CA,CO,ID,NV,OR, UT, VW, WY, and parts of NM, MT,SD,TX	57 Members 19 IOUs 17 Municipal 16 Public power (includes 6cooperatives) 5 Government agencies 4 Associates	1.8 million (US & CAN)	48 million

SOURCE: NERC 1966 *Annual Report*; and the 1986 *Reliability Assessment: The Future of the Bulk Electric System in North America 1988-1997*, September 1988.

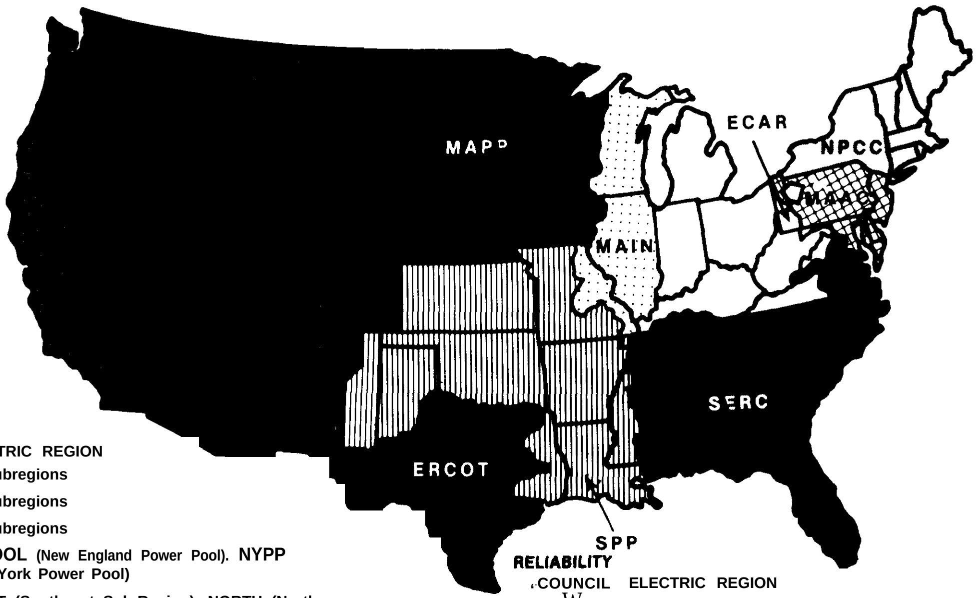
power suppliers. Private or investor-owned utilities operate in all States, except Nebraska. They dominate power generation, transmission, and wholesale and retail sales in all but one region (East South Central). In Hawaii, all power is supplied by private utilities. In the South and West, public power, cooperatives, and Federal power agencies account for a larger portion of sales to retail customers than elsewhere in the Nation, reflecting the historical role of these entities in the electrification of these

Table 6-2—Characteristics of Electric Utilities by NERC Region

Region	Projected 1988 installed capacity (MW)	Projected 1988 capacity margin (percent summer) (percent winter)	1988-97 avg. growth (percent summer) (percent winter)	1988-97 avg. annual NEL growth (percent)	Dominant fuels (percent)	Projected 1988 net imports (million kWh)	1988 Capital spending (billion of dollars	Transmission network-1987 (circuit miles)
ECAR	97,380	23.0 27.0	1.6 1.7	1.5	Coal (90)	−19,950	3.3	15,764
ERCOT	49,880	21.3 37.1	2.4 3.2	2.9	Gas/oil (46) Coal (40)	1, 58	1.7	6,871
MAAC	48,582	19.0 34.3	1.3 2.0	1.8	Coal (53) Nucl (31)	24,587	3.2	6,552
MAIN	49,607	25.4 40.9	1.5 1.9	1.7	Coal (54) Nucl (44)	1		5,397
MAPP	30,6 9	28.4 37.9	1.5 1.6	1.7	Coal (67) Nucl (67)	−8,057	1.0	13,827
NPCC	53,7 4	22.1 26.5	1.9 1.6	1.8	Nucl (28) Gas/oil (37) Coal (19) Hydro (14)	26,605	1.9	6,046
	139,334	20.0 23.8	2.4 2.4	2.4	Coal (60) Nucl (27)	−9,218	7.2	26,899
	65,621	26.7 45.5	1.9 2.2	1.9	Coal (54) Gas (26) Nucl (16)	−442	1.5	0•
WSCC		31.5 36.7	1.9 1.7	1.8	Coal (35) Hydro (33) Nucl (14)	38,248	5.9	In
TOTAL	657,759	24.3 32.8	1.9 2.0	2.		72,988	27.5	1

SOURCE: Office of Technology Assessment, from various NERC publications.

Figure 6-2-Electric Regions in the Contiguous United States



RELIABILITY COUNCIL	ELECTRIC REGION
ERCOT	No Subregions
MAAC	No Subregions
MAPP	No Subregions
NPCC	NEPOOL (New England Power Pool). NYPP (New York Power Pool)
SPP	SOEST (Southeast Sub-Region). NORTH (Northern Sub-Region). WCENT (West Central Sub-Region)
MAIN	CECO (Commonwealth Edison Company). SCIM (South Central Illinois-East Missouri Group). WIUM (Wisconsin-UPPer Michigan Systems Group).
SERC	FCG (Florida Electric Power Coordinating Group). SOCO (Southern Company Group). TVA (Tennessee Valley Authority) VACAR (Virginia-Carolinas Group)
WSCC	RMPA (Rocky Mountain Power Area). NWPP (Northwest Power Pool Area). AZNM (Arizona-New Mexico Power Area). CASN (California-Southern Nevada Power Area)
ECAR	APS (Allegheny Power System). WOIM (West Virglnia-Ohio-Indlana-Michigan Systems). WPANCO (Western Pennsylvania-North Central Ohio Group). CDH (Cincinnati-Day ton-HamiltOfl Group). KY (Kentucky Group). IND Indiana Group). LMS (Lower Michigan Systems)

SOURCE. Office of Technology Assessment, 1989.

regions. (These numbers can be somewhat misleading, however, because many public power utilities purchase wholesale power generated by private companies.)

Among investor-owned utilities, the large holding company power systems are important regional entities which control access to major regional transmission facilities. Their size, strategic locations, and financial resources would make them formidable competitors in large regional markets under any competitive industry structure. Regulated holding companies are important regional intluences in the Northeast Power Coordinating Council (NPCC), MAAC. East Central Area Reliability Coordination Agreement (ECAR), SERC, and SPP.

REGIONAL DIFFERENCES

The electric power industry displays regional variations in demand growth rates, generating capacity, capacity margins. fuel use, levels of reliability, and capital spending, as well as the potential for nonutility generation. Some of these differences are summarized in table 6-2.

Electricity Demand Growth Rates

NERC indicates that U.S. demand for electricity or net energy for load (NEL) will grow at an average annual rate of 2.0 percent between 1988 and 1997.[6]

Nationally, this is a downward revision of overall demand projections from those published by NERC

[6]North American Electric Reliability Council, *1988 Electricity Supply and Demand for 1988-1997*, October 1988, p. 18. Electricity demand is measured as net energy for load--defined by NERC as the annual electric energy needed to serve the utilities' customers. NEL includes transmission losses and represents the electrical energy generated by the utilities' own generating sources plus electrical energy purchases from other utilities and from nonutility generation facilities, less electrical energy sales to other utilities. NEL does not include energy pumping requirements for pumped storage generating facilities. NEL is roughly equivalent to DOE'S Net Generation.

Table 8-3-Capacity, Generation, and Sales by Class of Ownership and Region, 1987 (percent by region)

NERC[a] region / Class of ownership	Number of utilities	Installed capacity (percent)	Net generation (percent)	Sales to ultimate consumers (percent)
ECAR:				
Private	50	88.1	90.9	88.7
Public/State	230	7.6	3.0	5.7
Cooperative	113	4.4	6.1	5.6
Federal	—	—	—	—
ERCOT:				
Private	7	40.5	81.0	80.8
Public/State	57	57.4	15.9	12,4
Cooperative	65	2.1	3.0	6.8
Federal	—	—	—	—
MAAC:				
Private	19	96.5	98.3	95.1
Public/State	58	3.5	0.4	1.8
Cooperative	22		1.3	3.1
Federal	—	0*	0	—
MAIN:				
Private	22	96.9	97.5	91.5
PublicState	149	2.4	1.5	5.5
Cooperative	51	0.7	0.9	3.1
Federal	1	0	0.1	0
MAPP(U.S.):				
Private	18	51.5	48.4	59
Public/State	497	28.9	25.3	26.3
Cooperative	189	19.5	26.3	14.7
Federal	—	—	—	—
NPCC(U.S):				
Private	62	85.4	81.7	88.8
Public/State	134	14.6	18.2	10.7
Cooperative	16	•	•	0.5
Federal	—	0	0	0
SERC:				
Private	22	69.9	68.1	64.6
Public/State	312	8.3	7.7	20.4
Cooperative	187	1.6	6.1	11.8
Federal	2	20.2	18.1	3.2
SPP:				
Private	20	79.9	77.1	77.9
Public/State	293	11.4	7.1	9.5
Cooperative	158	8.7	13.2	12.6
Federal	1	0	2.6	0
WSCC(u.s):				
Private	32	55.5	51.9	64.3
Public/State	240	41.7	20.9	24.8
Cooperative	139	2.8	3.5	4.3
Federal	6	0	23.7	6.6
NERC[b](U.S):				
Private	252	73.5	75.2	77.0
Public/State	1,970	18.6	10.5	14.2
Cooperative	940	3.6	5.8	6.9
Federal	10	4.3	8.5	1.9

[a] North American Electric Reliability Council.
[b] Excludes Alaska and Hawaii.
*The absolute value of the number is less than 0.5.

NOTES: Totals may not equal sum of components because of independent rounding. Data shown, except for installed capacity, are preliminary data reported onthe EnergyInformation Administration Form EIA-861 The EIA-861 data were used since net generation and sales data are both reported on that form The data for net generation and sales to ultimate consumers may not agree with numbers published in EIA reports, which are based on the Form EIA 759, "Monthly Power Plant Report," and the Form EIA-826, "Electric Utility Company Monthly Statement."

SOURCE: Energy Information Administration, Form EIA-860, "Annual Electric Utility Report, Preliminary Data."

in 1987 and continues a recent trend.[7] All NERC regions except NPCC (U.S. portion) and MAAC projected lower 10-year NEL growth in 1988 than they did in 1987. Projected regional NEL growth rates for 1988-1997 vary considerably. (See table 6-2.) They range from a high of 2.9 percent in the Electric Reliability Council of Texas (ERCOT) region to a low of 1.5 percent in the ECAR region. Variations are evident within regions as well. For example, the Western Systems Coordinating Council (WSCC) region projects a growth rate of 1.1 percent for the Northwest Power Pool Area, but a 3.4 percent growth rate for the Arizona-New Mexico Power Pool Area for the same period. What causes these fluctuations in growth rates among regions? Population growth, climate, industrial activity, regional nonutility generation capacity, and cost are just a few of the factors that influence demand growth.

Peak demand for electricity in the United States is highest in the summer. NERC projects that U.S. summer peak load will likely grow at an annual rate of 1.9 percent between 1988-1997; projected regional summer peak growth rates range from 1.3 percent in MAAC to 2.4 percent in ERCOT and SERC (see table 6-2). Winter peak demand has been growing faster than summer peak in six of the nine NERC regions; these are ECAR, MAAC, MAPP, Mid-American Interconnected Network (MAIN), ERCOT, and SPP. All six regions are expected to remain summer peaking up to 1997.

Generating Capacity

The amount, type, and age of installed generating capacity also varies by region, as does the pace of planned additions (see figure 6-3 and table 6-4). These differences reflect varying load characteristics (population, climate, economic activity) and resource availability.

According to NERC, most regions currently have more than enough capacity to meet their increasing needs under most circumstances for several years at least. This assessment rests on two critical assumptions: that electricity consumption increases at the projected growth rates; and that existing and planned generating capacity is available when needed.

This assessment of adequacy includes built-in safety factors in both a 15 to 20 percent minimum reserve capacity and other capacity that is uncounted to allow for scheduled maintenance and could be used if needed. Even so, if actual demand growth exceeds the resumption or if existing and planned generating capacity levels are not reached, several regions and systems could see increased reliability risk or experience actual shortfalls in electricity supplies. Among the analysts that have examined these prospects, there is some disagreement about when and where additional generation capacity may be needed.[8] The disagreements are rooted in differing expectations over future growth in electricity demand and whether or not planned capacity is built as scheduled.

Generation and Fuel Use

More than half of the electricity generated in the United States in 1987 (about 2.6 million gigawatt hours (GWh)) came from three regions: SERC, WSCC, and ECAR. Figure 6-4 shows electricity generation by fuel and region.

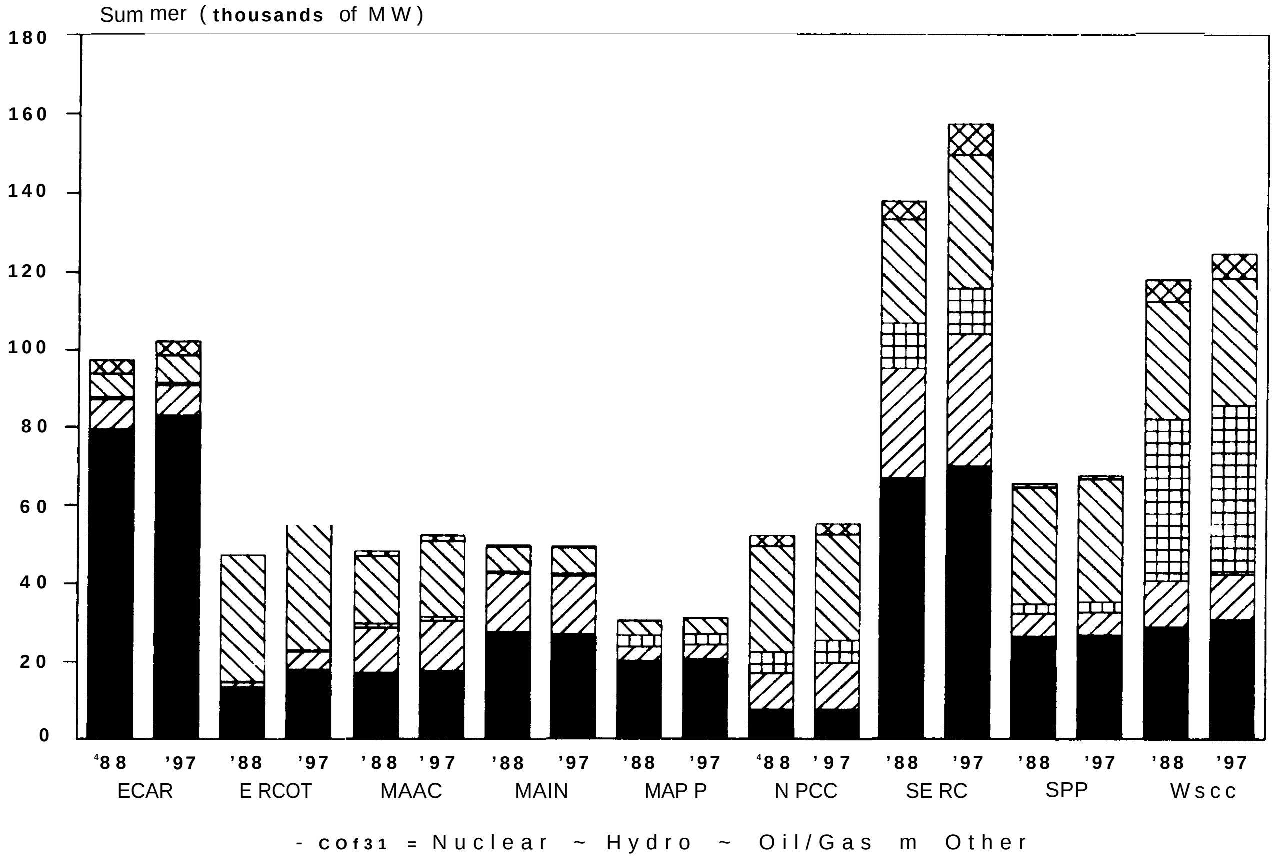
About 55 percent of the electricity generated in 1987 came from coal-fired plants. Six regions used coal for more than 50 percent of their electricity generation—ECAR, MAAC, MAIN, MAPP, SERC, and SPP. Two regions, MAIN and MAAC, generated a significant percentage of their power from nuclear plants. Hydropower is an important generating source in the U.S. portion of WSCC, accounting for about one-third of the electric energy production in that region in 1987, an unusually dry year. Hydroelectric plants also contributed 15 percent of generation in NPCC in the United States.

In some regions, the oil and gas capacity base is quite high. NERC projects that oil and gas will provide about 65 percent of capacity in ERCOT, over 50 percent in NPCC (U.S. portion), and 45.5 percent in SPP. Oil and gas plants are generally used for peaking power, but in some regions they also

[7] Ibid. These 10-year demand forecasts, are of course highly uncertain. To account for this uncertainty, NERC also estimated that the actual annual NEL growth woutd fall within a range of 0,9 percent per year to 3.5 percent per year. NERC did not provide comparable ranges for regional forecasts.

[8] See for example, U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, "Staff Report: Electric Power Supply and Demand for the Contiguous United States 1987 -1996," DOE/IE-0011, February 1988; Amy Abel, "Canadian Electricity, the U.S. Market and the Free Trade Agreement," Congressional Research Service Report 88-427 ENR, July 5, 1988.

Figure 6-3-installed Generating Capacity, 1968 and 1997



SOURCE: Office of Technology Assessment from NERC data.

contribute significantly to meeting base-load needs. For example, ERCOT generated 46 percent of its electricity from oil and gas in 1987, and NPCC-U,S. produced almost 39 percent of its electricity from oil and gas,

Capacity Margins

Regional and individual utility variations in capacity margins reflect differences in system characteristics, such as the duration of the peak load season and the outage rates for different ages, sizes, and types of generation capacity. Also, differences in the availability of supplementary bulk power from other systems will affect capacity margins. See table 6-5 showing projected capacity margins from NERC by region for 1988-1997 and figure 6-5 showing projected reserve margins at the time of regional peak demand.

Determination of adequate capacity margins varies from region to region with a margin of 15 to 20 percent generally considered desirable. See discussion in chapter 4. NERC expects capacity resources in all regions to be adequate to meet projected demand in 1988-97; however, overall capacity margins will decrease over the same period.

One of the results of the lower capacity margins could be that some utilities may have less flexibility in dealing with more severe situations. Another result could be the increased likelihood of load curtailments if a shortage develops.

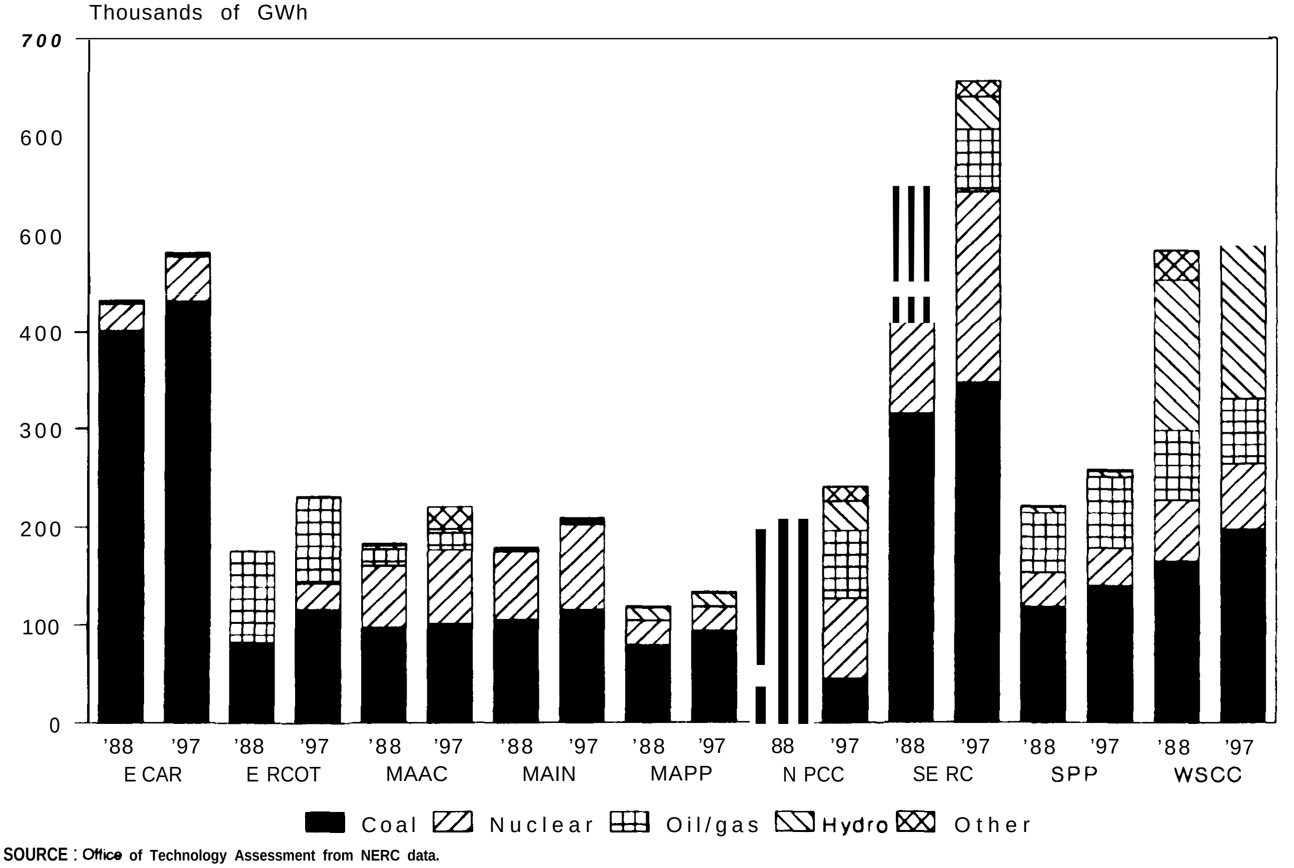
Still another result could be greater reliance on older generating units. This in turn will increase

Table 6-4--Life Extension Resource Base: Age of Fossil-Fired Steam Plants in 1995 by Region

Region	Fossil-fired capacity ±30 years old in 1995 MW	As a percent of fossil-fired capacity	As a percent of all installed capacity
ECAR	33,335	32.9	31.9
ERCOT	12,186	20.4	22.0
MAAC	11,589	35.5	22.0
MAIN	14,172	41.3	28.0
MAPP (U. S.)	6,695	25.8	22.5
NPCC (U. S.)	16,806	52.6	30.0
SERC	32,239	35.8	20.9
SPP	21,359	30.0	32.0
WSCC	24,811	39.5	18.5

SOURCE: Office of Technology Assessment, from data generated by E.H. Pechan & Associates, December 1984, and North American Electric Reliability Council, *1987 Electricity Supply and Demand for 1987-1996*, November 1987.

Figure 6-4-Projected Electrical Energy Production by Fuel, 1988 and 1997



SOURCE : Office of Technology Assessment from NERC data.

maintenance requirements and result in more outage time, as well as an increase in sulfur oxide emissions. A number of developments could easily change supply adequacy or excess capacity into a shortage situation. These include delayed capacity additions, nuclear safety concerns which result in

Table 6-5-Estimated Regional Capacity Margins (percent of planned capacity resources)

Regions (U. S.)	1988 summer	1997 summer
ECAR	23.0	20.5
ERCOT	21.3	17.8
MAAC	19.0	20.3
MAIN	25.4	15.2
MAPP	28.4	20.9
NPCC	22.1	20.5
SERC	20.0	17.7
SPP	26.7	16.6
Wscc	31.5	25.5
Total NERC	24.3	19.9

SOURCE: North American Electric Reliability Council, *1988 Electricity Supply & Demand for 1988-1997*, October 1988, p. 24.

unit deratings or delays in operation, and higher than predicted demand growth rates.

Generation Reliability[9]

How a NERC region assesses generation reliability depends on the structural relationships between the regional council and its member systems and the degree to which various approaches are formalized by legal documents. Nearly all regions employ a probabilistic approach to generation adequacy analysis. The industry standard of 1 day in 10 years loss of load probability is widely shared, 10

Significant parameters used in assessing adequacy include demand growth, load patterns, weather, potential slippage of in-service dates, transmission ties, and fuel and unit availability. Most regions encourage the use of a normal weather parameter in determining demand. With regard to capacity characteristics, all regions have a formal requirement for establishing the capacity rating. Also, all regions use either a probabilistic or judgmental evaluation of the effects on adequacy of operational capacity availability rates.

Capital Spending

The Electric Light and Power Survey of investor-owned utilities, cooperatives, and public power organizations indicated that regional capital investment will follow population and business growth trends. For example, the greatest spending activity will occur in the SERC and WSCC regions, which have the greatest capacity and the highest demand. Table 6-2 shows capital spending by region for the 1988-92 period.

Electricity Prices

Retail electricity prices vary by region and by class of service. Department of Energy (DOE) data for 1987 show that **average** retail residential electricity prices ranged from 6.89 cents per kWh in WSCC to 9.76 cents in Alaska and 9.69 cents in NPCC. Electricity prices for commercial and industrial customers also varied considerably. The NPCC and Alaska regions were the most expensive for commercial customers; industrial customers in Alaska, MAAC, and NPCC paid the highest prices. Table 6-7 shows the average retail electricity prices by class of service and region for 1986 and 1987.

NARUC's (National Association of Regulatory Utility Commissioners) 1986-87 winter survey of residential electric bills found that costs varied by as much as 300 percent regionally. Costs ranged from 4 cents per kWh in Spokane to 13.1 cents per kWh in New York. The average was 8.1 cents nationally.[11]

The Northeast and Pacific regions were the most expensive, while the Northwest and Rocky Mountain areas were the least expensive, according to NARUC.[12] Table 6-8 shows the ten most and ten least expensive service territories in the United States.

TRANSMISSION

NERC reports that there is no major transmission **surplus** in any region of the country. In MAAC, for example, the transmission system is reported to be fully loaded much of the time. Overall, new transmission line construction is declining. In fact, since 1985, the total amount of planned transmission facilities has declined, both in the United States and Canada. This decline is due in large part to the

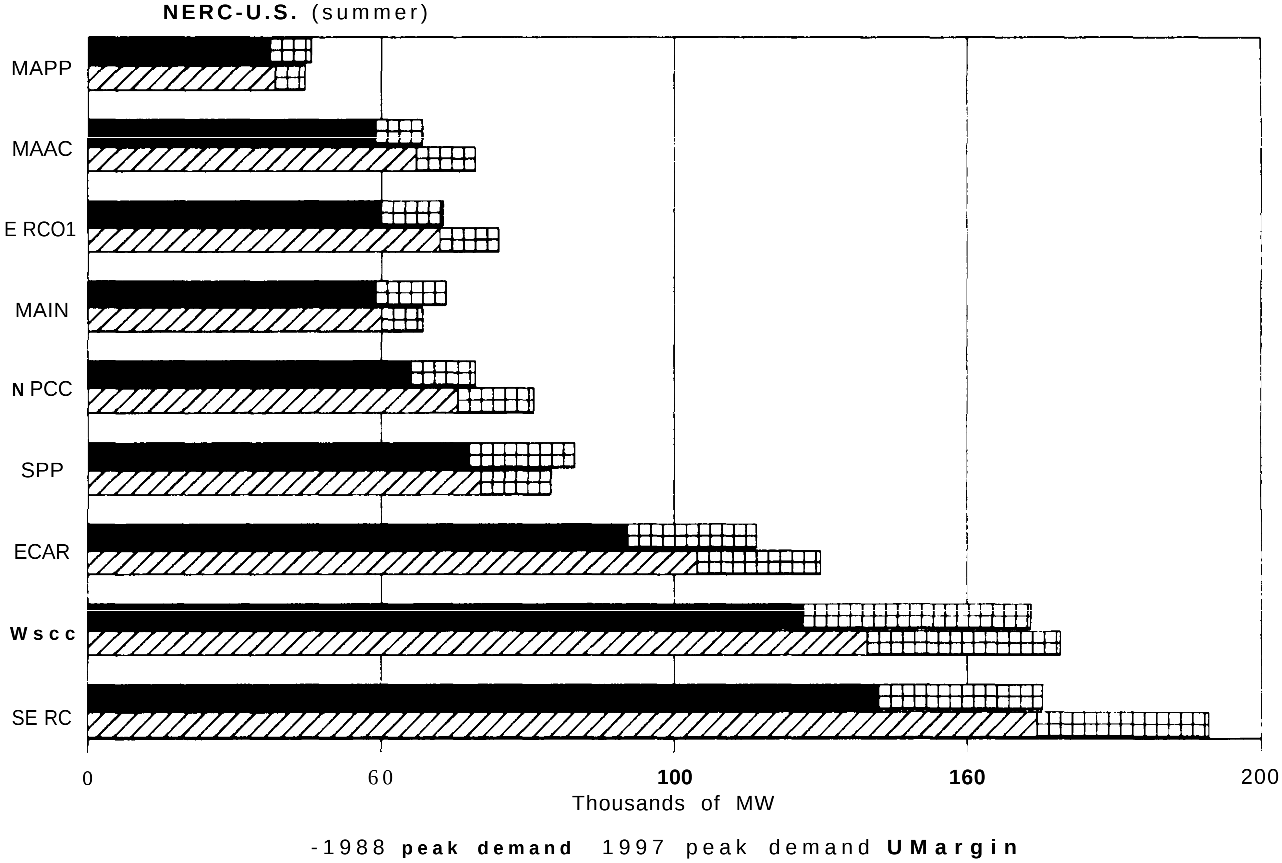
[9] Reliability Council Survey Responses, supra note 2, at p. 12.

[10] See discussion of 1 day in 10 years loss of load probability (LOLP) in ch. 4.

[11] The National Association of Regulatory Utility Commissioners (NARUC) 1986-87 Winter Survey of Residential Electric Bills, *Electric Light and Power*, vol. 66, No. 3, March 1988, p. 3.

[12] Ibid.

Figure 6-5-Estimated Margins at the Time of Regional Peak Demand



SOURCE: North American Electric Reliability Council.

cancellation or deferral of new generation additions and their related transmission facilities (see figure *6-6).* In addition, many utilities are giving greater emphasis to efforts to increase the capability of *existing* transmission systems because of the difficulties in siting and building new lines.

NERC expects that some transmission systems will continue to be heavily loaded by economy energy transfers, both within and among regions, during the 1988-97 forecast period. These transfers are expected to increase whenever sufficient fuel price differentials exist. For example, within regions, hydrogenerated energy will continue to be transferred from the Northwest area of WSCC to the Southwest area, provided there are no dry spells. Also, because of loop flow and parallel path phenomena, energy transfers among systems can increase loadings in other systems that are not parties to the transfer. MAAC's transmission system adequacy has been affected by New York Power Pool (NYPP) imports of Canadian hydropower, for example. To counteract these increases in interregional loading, NPCC and MAAC have reached an agreement on what constitutes normal and excessive use of each other's transmission system. The agreement includes the purchase and installation of phase shifting transformers near the New York/New Jersey border. OTA's case study "Importing power from Canada to New England"[13] illustrates this particular transmission problem.

13 For more detailed information on the OTA case study, see Casazza, Schultz & Associates, Inc., "Case Studies of Transmission Bottlenecks," OTA contractor report, Nov. 30, 1988.

Table 6-6-Projected 5-Year Capital Expenditures (by NERC Region–millions of dollars)

Region	1988	1989	1990	1991	1992	5-year total
ECAR	3,303	3,204	2,756	2,460	2,022	13,745
ERCOT	1,676	1,264	1,188	1,184	1,502	6,814
MAAC	3,182	2,939	3,012	2,729	2,195	14,057
MAIN	1,897	1,490	1,428	1,370	1,503	7,688
MAPP	1,029	1,112	1,102	1,090	1,020	5,353
NPCC	1,876	1,726	1,782	1,800	1,518	8,702
SERC	7,189	6,766	7,030	6,703	6,224	33,912
SPP	1,463	1,360	1,310	1,389	1,369	6,891
WSCC	5,870	4,784	4,504	4,565	4,886	24,609
Total	27,485	24,645	24,112	23,290	22,239	121,771

SOURCE: *Electric Light & Power*, "Electric Utilities Will Increase Spending Plans Through 1992," vol. 66, No. 1, January 1988, p. 12.

Table 6-7—Average Retail Electricity Prices by Class of Service and Region, 1986-87 (cents/kWh)

NERC region	Residential	Commercial	Industrial
1987:			
ASCC	9.76	8.48	7.86
ECAR	7.08	6.68	4.44
ERCOT	6.68	5.81	3.99
	9.28	9.26	6.69
MAAC	9.05	8,32	6.05
MAIN	9.12	7.54	5.01
MAPP	6.96	6.22	4.34
NPCC	9.69	9.06	5.74
PRTER	7.51	9.83	7.78
SERC	6.96	6.55	4.67
SPP	7.26	6.64	4.37
Wscc	6.89	7.31	5.47
:Fc	9.11	8.27	7.49
ECAR	7.13	6.78	4.63
ERCOT	6.70	5.91	4.20
HI	9.13	9.03	6.41
MAAC	9.38	8.83	6.52
MAIN	8.67	7.69	5.07
MAPP	6.83	6.27	4.53
NPCC	9.65	9.26	5.73
PRTER	6.89	9.17	7.27
SERC	6.95	6.58	4,73
SPP	7.36	6.78	4.60
Wscc	6.81	7.37	5.65

NOTES: Totals may not equal sum of components because of independent rounding.

SOURCE: Energy Information Administration, Form EIA 661, "Annual Electric Utility Report, preliminary data.

Assessing transmission constraints is a difficult task. Given the dynamic nature of bulk power transactions, the location and seventy of transmission system constraints often change. The ccmstraints that have been identified in various reports differ in nature and are caused by a variety of factors, as discussed in chapter 4. Because of these and other factors, no comprehensive list of bottlenecks has been developed. OTA has not investigated the cited incidence of transmission constraints.

The 1986-1987 National Governors' Association (NGA) survey of NERC regional councils, for example, identified a wide range of situations creating transmission limitations. However, many of these limitations may no longer be considered as such because conditions have changed since the time of the survey.

NERC has also listed impediments to transfer in its 1984, 1985, 1986, and 1987 assessments. Over that period some of those impediments have been solved or eased, while other projects remain delayed by regulatory actions. A 1985 ECAR/MAAC Coordinating Group report identified bottlenecks to the transfer of power from ECAR to MAAC. The primary restriction to ECAR-MAAC transfers, according to the report, has been voltage conditions in MAAC and eastern ECAR. Also, parallel path flows resulting from power transfers among utilities in the Northeast are cited as another limiting factor.

An OTA survey of some 23 utilities conducted in July 1988 found few cases of utilities having to restrict bulk power transactions or limit economic dispatch significantly because of transmission constraints. However, most respondents had to limit or operate outside optimal economic dispatch occa-

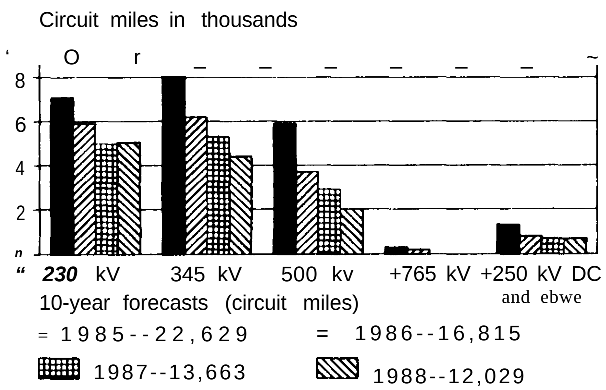
Table 6-&The 10 Most Expensive and 10 Least Expensive Service Territories in the Continental United States

Company	State	Total bill	Average cost cents/kWh 500 kWh"	Rank
Ten most expensive service territories:				
Consolidated Edison Co. of N.Y.	New York	$195.91	$0.131	1
San Diego Gas & Electric	California	$179.91	$0.120	2
Long Island Lighting	New York	$177.56	$0.118	3
Philadelphia Electric	Pennsylvania	$175.87	$0.117	4
Orange & Rockland Utilities	New York	$168.77	$0.113	5
Texas New Mexico Power	New Mexico	$167.33	$0.112	6
Central Vermont Public Service	Vermont	$166.80	$0.111	7
Delmarva Power& Light	Virginia	$164.82	$0,110	8
Public Service Electric & Gas	New Jersey	$162.36	$0.108	9
Northern Indiana Public Service	Indiana	$162.09	$0.108	10
Ten least expensive service territories:				
Washington Water Power	Washington	$59.97	$0.040	191
Washington Water Power	Idaho	!$62.73	$0.042	190
Idaho Power	Idaho	$63.17	$0.042	189
CP National Corp.	Oregon	$65.85	$0.044	188
Pacific Power & Light	Washington	$67.95	$0.045	187
Idaho Power	Oregon	$71.34	$0.048	186
Portland General Electric	Oregon	$72.84	$0.049	185
Pacific Power & Light	Montana	$73.32	$0.049	184
Puget Sound Power& Light	Washington	$75.74	$0.050	183
Minnesota Power & Light	Minnesota	$79.48	$0.053	182

"Based on *customer usage* of 500 kWh per month.

SOURCE: NARUC, "1986 87 Winter Survey of Residential Electric Bills, *Electric Light &* Power, March 196S, p. 3.

Figure 6-6-Planned Transmission Additions
(NERC-U.S.)



SOURCE: North American Electric Reliability Council.

sionally. The utilities' responses generally were that the constraints were not significant enough to offset the costs of correcting them.

Demand for Increased Transmission Access

Determining which regions and utilities are most likely to request wheeling is a difficult task at best. However, several factors, such as price differentials, surplus generating capacity, and load diversity, indicate that transmission access requests are likely to increase in some regions. Among these regions are MAPP, MAIN, WSCC, and NPCC. Both MAPP and MAIN have abundant coal-fired capacity which could be exploited by selling to utilities outside the regions. MAIN also has substantial interregional transfer capability. Because of load diversity, base-load capacity surpluses, and large fuel price differentials, the WSCC subregions are likely to continue to take advantage of energy economy transfers. Also, the NPCC region, with its fuel price differentials and its growing reliance on Canadian generating resources, is more likely to seek additional transmission services.

A recent private consulting firm's report on wheeling indicated that if expanded transmission access is allowed, some regions could become major power exporters, and the total cost of electric generation and transmission in North America could be cut by $1.65 billion a year. Among the potential beneficiaries of an open transmission access environment could be the Rocky Mountain and the Arizona-New Mexico subregions of the WSCC, MAPP, and MAAC, according to the report.[14]

The NGA survey of NERC regional councils indicated that expanded transmission access could have an impact on reliability. ECAR and SERC respondents cited numerous problems with open access. These included scheduling generation and transmission maintenance, load dispatching problems, a decline in cooperation among utilities, and reliability impacts.

The responses differed among utilities within regions, however, Those utilities that could actively participate in competitive bidding were less resistant to expanded access. Joint action agencies, regardless of region, noted that open transmission access would be beneficial for a number of reasons. Competitive and economic opportunities were the two reasons most often cited.

NONUTILITY GENERATION

Fuel use and costs, demand growth rates, and regulatory policies determine the potential for nonutility generation (NUG) in any region.

Determining the amount of actual NUG capacity on line or planned is difficult. There is no comprehensive and up-to-date source of information on total megawatts for plants in operation, under construction, or in the planning stage. While the Federal Energy Regulatory Commission (FERC) keeps records of applications for qualifying facility status,[16] it does not track operational facilities. Moreover, the Energy Information Administration also has not collected independent information that tracks the growth of nonutility generation. Consequently, little information on total NUG capacity is available. Those attempting to determine capacity often use different definitions, leading to further variations in data.

Estimates of current and future NUG capacity vary by region and by sector, as well as by estimator. A number of reports have estimated current capacity and a few have even made projections. These include NERC, Edison Electric Institute, RCG Hagler, Bailly, Inc., and the Gas Research Institute.

Estimates of Total Nonutility Generation Capacity

Estimates of NUG capacity are being included, to a varying extent, in the NERC regional forecasts.[17] The decision of how to treat N UG capacity additions rests with the local utility and regional council. NUG capacity additions in the latest NERC projections were notable in WSCC, SERC, NPCC, and MAAC regions. NERC projected a total of 27,656 MW of NUG capacity by 1997—about 22 percent of total planned additions. Much of NERC's projected NUG capacity, however, is characterized as ''unknown, " either as to location, fuel, or project. NERC estimates current NUG capacity to be 7,741 MW as shown in table 6-9.[18] This NERC estimate most probably understates the actual NUG capacity.

Based on a more extensive survey, the Edison Electric Institute (EEI) also has calculated the amount of nonutility sources of generation, both used internally in industry (self-generation) and sold to utilities (cogeneration). In 1986, EEI estimated that NUG capacity reached 25,321 MW, a 10 percent increase over 1985 figures. Cogenerators accounted for about 73 percent of total capacity or 18,448 MW. About two-third's of the total cogenerated capacity are qualified facilities under the Public Utility Regulatory Policies Act (PURPA).[19] The industries with the greatest cogeneration capacity are the chemicals and paper and lumber industries, followed by the oil and gas and metal industries. Table 6-10

[14] WEFA Group, "Power Wheeling in North America, " *Electrical World*, vol. 202, No, 3, March 1988, pp. 13-14.

[15] Ohio Public Utilities Commission Staff, Summary of Utility Interviews, Aug. 12, 1988 (OTA contractor document).

[16] The number and size of PURPA QFs filed with FERC has increased markedly in recent years. In 1980, FERC received 29 applications for 704 MW of PURPA qualified capacity. But by the third quarter of 1987, FERC received 3,571 applications for 58,717 MW of nonutility capacity.

[17] Utilities differ in how NUG capacity is counted. Some utilities report NUG facilities under total generating capacity, others treat the capacity as a reduction in load, while still others do not include NUG capacity at all in reporting system capacity and generation.

[18] NERC, *1988 Reliability Assessment: The Future of Bulk Electric System Reliability in North America 1988-1997*, September 1988, p. 15.

[19] Edison Electric Institute, *Capacity and Generation of Nonutility Sources of Energy*, 1988, p. 11.

Table 6-9-Actual and Projected Nonutility Generation Capacity (summer MW)

NERC regions	Actual 1987	1988	1997
ECAR	148	192	2,308
ERCOT	2,956	2,536	2,506
MAAC	183	269	3,126
MAIN	0	0	12
MAPP	0	216	281
NPCC	874	1,517	4,572
SERC	961	1,526	5,910
SAP	31	47	582
Wscc.	2,588	4,835	8,359
Total	7,741	11,139	27,656

SOURCE: North Amerrcan Electric Reliability Council, 1988 *Electricity Supply* arrd *Demand for 1988-97*, October 1988, app. A, p.20.

and figure 6-7 summarize EEI regional nonutility generation data.

Another report by a private consulting firm, "Profiles of Cogeneration and Small Power Markets,"[20] indicated that 1988 cogeneration and small power production capacity was 24,833 MW. An additional 38,345 MW are under construction or in design, according to the report.[21] Cogeneration projects outnumber small power projects by a margin of 3-to-I. And, in terms of capacity, cogeneration outnumbers small power by nearly a 5-to-1 ratio.[22]

The Gas Research Institute has been monitoring nonutility generation, particularly gas-fired cogeneration. The GRI report, *Impact of Cogeneration on Gas Use,* estimated cogeneration capacity at 19,000 MW in 1985. GRI expects 25,000 MW to be added by the year 2000.

Nonutility Fuel Use

Natural gas has been the predominant choice for NUG facilities. Recent lower prices and the availability of natural gas have contributed to its popularity among nonutility generators. Coal-fired and wood-burning facilities also provide significant amounts of NUG capacity. A large percentage of natural gas-fired capacity is in ERCOT (Texas), WSCC (California), SPP (Louisiana), and SERC. The SERC region also has a concentration of wood-burning cogeneration facilities. And MAAC (Pennsylvania) and NPCC (New York) have significant coal-fired NUG facilities. Combined cycle systems and boiler/steam turbine systems provide most of the capacity.

Regional Nonutility Generation Potential

All regions of the country have some level of nonutility generation. In the MAAC region, there is considerable potential for development of nonutility generation. NERC expects that nonutility generation will account for more than 40 percent, or 2,860 M W, of new capacity additions over the next 10 years.

According to a recent survey of qualifying facilities in the United States, cogeneration growth in the Mid-Atlantic has surpassed that of the Pacific and Gulf Coast areas.[23] New Jersey, New York, and Pennsylvania lead the nation with 13,262 MW of potential qualifying facility (QF) power, followed by the West South Central and Pacific regions.[24]

In its latest report *Electric Power Outlook* 1968-2O04, the NYPP has indicated that a total of 2,577 MW of nonutility generation will be added between 1988 and 2002. This figure is more than twice the 1,081 MW predicted for the same period in NYPP's previous year's report. Without these nonutility generation additions, margins may not be adequate by the mid- 1990s, according to the report.[25]

The importance of nonutility generation to meet demand in New England has been voiced by both NERC and the New England Conference of Governors. A recent New England Governors' Conference report indicated that cogeneration and small power production must play increasingly important roles if the New England States are to meet energy demand.[26] Also, NERC has indicated that the develop-

[20] RCG Hagler, Bailly, Inc., *Profiles of Cogeneration and Small Power Markets.* 1988 *edition.*

[21] *Energy User News,* "Mid-Atlantic Area Forges Ahead in Cogeneration Development," vol. 13, No. 21, May 23, 1988, pp. 1, 8.

[22] *Electric Utility Week,* "Cogeneration Development This Year Seen Off A Bit, But Still Active," Apr. 25, 1988, p. 12.

[23] *Energy User* News, supra note 21.

[24] Ibid.

[25] *Electric Utility Week,* "Cogeneration, Demand Cut, Nuclear seen Necessary To Get NYPP to 2004," May 30, 1988, p. 1 1

[26] *Cogeneration,* "Big Role for Cogeneration in New England's Energy Future," vol. 4, No. 1, January-February 1987, p. 28.

Table 6-l Nonutility Generating Capacity by Region

Region	States	NERC regions full/partially included	1986 nonutility capacity	Percent cogeneration	Percent cogeneration qualified
New England	ME, VT, NH, MA, CT, RI	NPCC	1,404 MW	480/o (667 MW)	61Y.
Mid-Atlantic	NY, NJ, PA	NPCC, MAAC	1,552 MW	67°/0 (1 ,045 MW)	72%0
East North Central	IL, IN, Ml, OH, WI	MAIN, ECAR, MAPP	2,840 MW	690/o (1 ,950 MW)	230/'
klkst North Central	1A, KS, MN, MO, ND, NB, SD	MAPP, SPP	661 MW	360/. (239 MW)	36?40
South Atlantic	DC, DE, FL, GA, MD, NC, SC, VA, Wv	MAAC, ECAR, SERC	3,989 MW	840/o (3,351 MW)	610/0
East South Central	AL, KY, MS, TN	SERC, SPP	1,104 MW	96Y0 (1 ,064 MW)	580/o
West South Central	AR, LA, OK, TX	SPP, ERCOT	7,751 MW	930/0 (7,231 MW)	780/.
Mountain	AZ, CO, ID, MT, NM, NV, UT, WY	WSCC, MAPP	420 MW	5570 (233 MW)	52%
Pacific	CA, OR, VW	WSCC	4,687 MW	38Y0 (1,816 MW)	97?40
Alaska			644 MW	10OO/o (644 MW)	
Hawaii			270 MW	770/0 (208 MW)	
Total			25,321 MW	18,448 MW	

SOURCE: Edison Electric Institute, *Capacity* and Generation ofiVon-UfdIty *Sources of Energy*, July 1988, pp. 26-27.

ment of nonutility generation is important to ensuring the NPCC's supply adequacy over the next 10 years. Between 1988 and 1997, nonutility generation capacity is expected to increase by 27 percent in New England and by 44 percent in New York, according to NERC.

ECAR expects nonutility generation to increase from 168 MW in 1988 to 1,329 MW by 1991. West Virginia is one of the States within this region that is taking a hard look at cogeneration as part of its long-range energy plan to make the State a regional electricity exporter. However, the State's cogeneration potential may be limited by overcapacity and low avoided-cost factors and by limitations on available transmission capacity to potential consumers in Northern States.[27]

ERCOT produces a great deal of nonutility generation, almost all of which is gas-fired. NERC projects that 2,537 MW or 5 percent of 1988 summer peak capacity resources will be supplied by nonutility generators, mostly cogeneration. Without the projected nonutility generation capacity additions, the region's 1997 capacity margin would decrease from 17.8 percent to 14.2 percent, according to NERC. Some of this cogenerated electricity was wheeled to utilities other than the connecting utility. NERC indicates that the figure maybe a.. high as 60 percent of NUG capacity under contract within ERCOT.

Other projections also show that cogeneration will make a significant contribution to capacity in Texas. The Texas Public Utilities Commission assembled a data base of State cogeneration projects that were either in operation, under construction, or being planned for service before the end of 1988. The data showed that Texas should have about 9,500 MW of cogeneration capacity in 1988.[28]

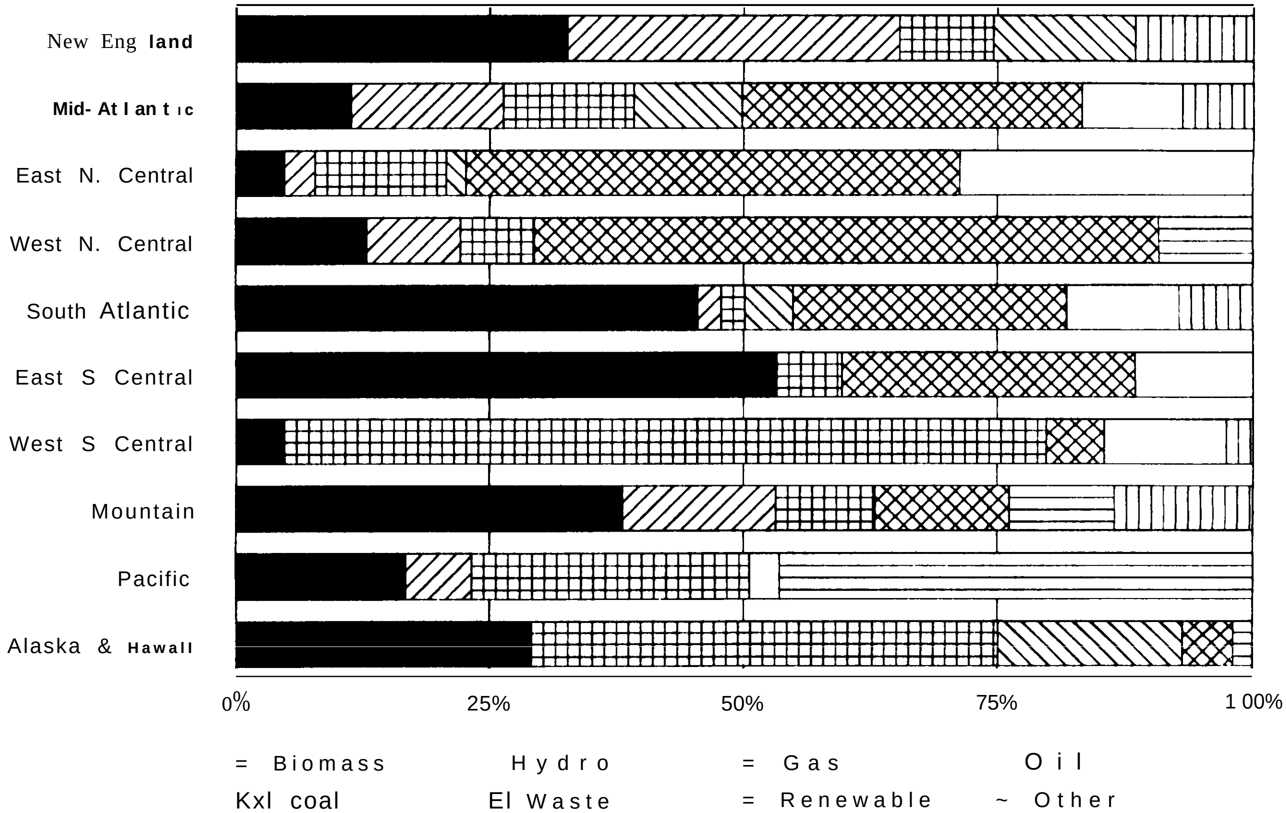
The largest number of cogenerators in Texas are in the oil, gas, and chemical industries. These industries have great cogeneration potential, as well as financial and political clout. Texas has taken steps to increase cogenerators' access to transmission lines to move power to nonlocal utilities, but state law explicitly prohibits retail or self-service wheeling.

SERC, the fastest growing region, expects about 6,200 MW of new nonutility generation by 1997. According to NERC, nonutility generation will continue to be an increasingly important source of new capacity for some systems of SERC. While nonutility generation is not expected to significantly

[27] *Cogeneration*, "In the States," vol. 4, No, 3, May-June 1987, p. 55.

[28] GRI, *Impact of Cogeneration on Gas Use in the Industrial and Electric Utility Sectors*, January 1986, p. ES-27.

Figure 6-7-Nonutility Fuels, 1966



Biomass includes agricultural waste, landfill, municipal solid waste, and wood.
Waste indudes anthracite culm, blast furnance gas, coke oven gas, digester gas, petroleum coke, refinery gas, refinery oil, sulfur combustion, waste gas, and waste heat.
Other includes nuclear, fuel cell, and projects which did not identify primary energy source.
SOURCE: Edison Electric Institute, *1986 Capacity and Gneration of Non-Utility Sources* of Energy (Washington, DC: July 1988).

penetrate the TVA service area, it is expected to contribute significantly to the Virginia-Carolina Region's (VACAR) capacity needs during the next decade. For example, Virginia Power signed seven contracts in mid-1987 for 1,181 MW of cogenerated power. The utility expects that 75 percent of its new capacity needs by 1990 must be met by cogenerated sources.[29] In addition, in March 1988, Virginia Power solicited bids for 1,750 MW of additional capacity. The solicitations generated interest from potential suppliers of about 27,000 MW, including some cogeneration and coal waste projects.[30] Detailed information on Virginia Power's bidding system can be found in box 5-B in chapter 5.

From 1988 through 1997, nonutility generation capacity additions represent about 31 percent of WSCC's planned additions. NUG additions will account for almost 5 percent of the region's total 1997 resources, according to NERC.

Of the four WSCC areas, the California-Southern Nevada Power Area is projecting the highest growth in nonutility generation. California leads the WSCC region in projected NUG additions. NUG capacity is forecast to increase from 1,740 MW in 1987 to 6,768 MW by 1997. These estimates differ significantly from those reported by the California Independent Energy Producers (CIEP). Based on the cogeneration/ small project quarterly reports issued by California

[29] *Cogeneration*, "Virginia Power Deals for 1,181 MW of Cogenerated Power for 1990 Delivery," vol. 4, No. 4, July-August 1987, p. 18.
[30] *Energy Daily*, '*Competitive Bidding: The 30% Solution," vol. 16, No. 99, May 24, 1988, p. 1

utilities, CIEP indicates that 5,218 MW of QF generation was on-line in California, as of the end of 1987. An additional 11,964 MW are under contract or in the discussion stage.[31] The increase in NUG facilities have been stimulated by the California regulatory commissions' interpretations of PURPA. Most of these facilities are base-load in nature, and many are small, low-voltage units. Because of the oversupply of NUGS in the mid- 1980s, the California Public Utility Commission suspended long-term contract offers. California has since developed a bidding system for acquiring long-term energy and capacity. (See box 5-C for more detailed information on the California bidding system.)

In contrast, growth in NUG capacity has been relatively slow in the Rocky Mountain Power Area. This may be attributed to the substantial amount of surplus coal-fired generating capacity available within the area, which results in low avoided costs. However, a recent flurry of QF proposals in Public Service Colorado's (PSC) service territory could increase the region's NUG capacity. PSC claims that if all the potential projects enter service. it would be buying 1,149 MW of nonutility generation by 1991—784 MW more than it had projected. This situation led the Colorado Public Service Commission to suspend the signing of new QF contracts in late 1987 for 60 days.[32] Colorado has since approved a bidding program for new supplies for PSC.

SPP anticipates nonutility generation capacity to reach 582 MW by 1997, or 0.9 percent of total capacity. Most NUG capacity is expected to develop in the West Central subregion of SPP. The NERC estimate probably understates current NUG capacity for this region. EEI, for example, reported that Louisiana alone accounted for 7 percent (1,972 MW) of the total U.S. nonutility generating capacity in 1986.

The planned use of nonutility generation in MAIN is modest compared to other regions. Nonutility generation is included as installed capacity in 1988 and only 12 MW is projected by NERC in 1997. The region's substantial low-cost coal-fired and nuclear capacity has dampened nonutility growth.

Nonutility generation also is a minimal part of MAPP's resource plans. NERC forecasts that by 1997, nonutility generation will represent less than 1 percent of total capacity.

Regional Experience With Nonutility Sources of Power

The recent growth in NUG capacity has benefited both utilities and customers, According to EEI, electricity sales to utilities from nonutility sources have increased six-fold since 1979. Almost all of the sales have been to the investor-owned segment of the industry. In 1985 and 1986, receipts grew at annual rates of 46 and 44 percent respectively, EEI reports.[33] But, this rapid growth has also raised some concerns by NERC over reliability. Some of these concerns include responsibility for reactive power support, voltage control, and the additional requirements imposed on utilities for supply planning uncertainty, transmission loading problems, and integration into utility operations. NERC and purchasing utilities face new challenges in how to handle the additional planning uncertainties of possible nonperformance or noncompletion of planned nonutility generation. To some extent, these concerns will be alleviated as the industry gains more experience in effectively integrating nonutility sources of supply.

Some regions have considerable experience in developing working arrangements for dealing with NUG power, including bidding. long-term contracts, pricing terms, and dispatchability provisions. For example, California regulators can require new cogeneration plants to follow load through the use of power-purchase contracts and regulation. Recently, the California Energy Commission has required that new 50+ MW cogeneration units agree to cycle as a condition of their siting permits. As of mid-1988, two "dispatchable load" contracts were in place and others were expected.[34]

According to NARUC, 24 States have adopted or plan to adopt competitive bidding as a means of procuring QF power. Among them are Massachusetts, Maine, and California. Nonprice factors, such

[31] California Independent Energy Producers, California Summary, Alternative Energy Projects (4th Quarter 1987).

[32] *Electric Utility* Week, "Independent Power," Dec. 28, 1987.

[33] Edison Electric Institute, supra note 19, p. 1.

[34] *Electrical World*, "Cogeneration: Threat or Opportunity?" vol. 202, No. 7, July 1988, p. 66.

as dispatchability, also can be considered in the bid evaluation. Michigan and Vermont are considering price-bidding systems. Washington State has proposed a bidding system for investor-owned utilities as a means of securing supplies from QFs under PURPA. Non-QF capacity would not be included under the State's new rule. The Washington proposal is modeled on the system in effect in Massachusetts.[35]

Other States—Connecticut, Rhode Island, and Virginia—have adopted or allow nonprice competitive systems. The nonprice systems are used for a number of reasons, which include encouraging QF development in States and avoiding the possibility of conflict with the legal requirements of PURPA. Several additional States are examining bidding systems: Idaho, Nevada, New Hampshire, New Mexico, Oregon, Pennsylvania, and Utah.

REGIONAL DIFFERENCES AND INDUSTRY CHANGE

The impacts of proposed regulatory and structural changes will differ for individual regions, States, and electric systems because of the differences among existing systems and the wide range of possible conditions and reactions that must be taken into account. Among the most significant regional influences will be:

- adequacy of electric power supplies to meet demand;
- transmission access including availability, adequacy, and pricing;
- the regulatory climate;
- the competitive environment; and
- impacts on retail customers.

These regional variations will strongly determine how well and how quickly proposals for change can be implemented.

Adequacy of Supply

Utilities base their assessments of power supply adequacy on past experiences and future assumptions about the interplay of electricity demand and growth rates and available power supplies. Changes in electricity demand are reflected in both net energy for load and peak demand and are influenced by weather patterns, economic activity, and the effectiveness of load management and conservation strategies. Power supply considerations include installed generating capacity, reserves margins, capacity availability, and the potential for bulk power purchases.

These assessments are inherently uncertain, and to counter the risk of underestimating demand, utilities in the past may have overstated potential demand growth in establishing their capacity needs (including a typical 15 to 20 percent capacity margin). In recent years, however, some utilities have tended to project 10-year demand growth rates that trail actually experienced increases in electricity use. At these lower demand growth rates, NERC currently forecasts that all its regions will have adequate electricity supplies through the mid 1990s. But if demand growth rates are higher than forecast, many regions could need additional capacity earlier than forecast. According to various analyses, areas with potential shortfalls in capacity margins at annual average growth rates exceeding 2 percent include MAAC, MAIN, MAPP, NPCC, SERC, and SPP.[36] The analyses were not in agreement on all regions, however.

In addition to differences in demand growth, various capacity availability factors can influence whether existing or planned generating facilities can be used to supply power when needed. In addition to the routine unavailability for regularly scheduled maintenance and the unpredictable but inevitable random forced outages, system characteristics and external events can affect capacity availability and reduce system reliability. For example, under some conditions regions that are heavily dependent on a particular fuel or generating source could face

[35] *Electrical World*, "Bl&J1~~ Systems: Who Has Them and why, " vol. 202, No. 3, March 1988, pp. 15-16. Based on National Independent Energy producers report "Pricing New Generation of Electric Power, A Report on Bidding."

[36] See for example, U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, "Staff Report: Electric Power Supply and Demand for the Contiguous United States 1987 -1996," DOE/IE-0011, February 1988; Amy Abel, "Canadian Electricity, the U.S. Market and the Free Trade Agreement, " Congressional Research Service Report 88-427 ENR, July 5, 1988.

capacity availability restrictions that exceed their capacity margins because of unforeseen fuel shortages or new environmental or safety requirements. This vulnerability may create a sudden need for replacement bulk power sources.

In ECAR, MAIN, MAPP, and SERC, over half of the installed generating capacity is coal-fired. In ECAR coal plants accounted for over 90 percent of electricity generated in 1987. If new environmental protection requirements are legislated to reduce emissions associated with acid rain and global warming, many of these coal plants, particularly the older ones, would be directly affected. In the extreme, compliance with emissions reduction strategies could shut down some of these plants temporarily or permanently.

ERCOT, NPCC, and SPP are heavily dependent on oil and gas generating capacity and would suffer adversely in the event of shortages or rapid price increases in oil and natural gas.

During 1988, drought and low flow conditions reduced the availability of hydroelectric plants in the West and South. Low flow conditions can reduce availability of water for cooling steam plants leading to a downrating of their capacity.

Safety considerations requiring the curtailment or shut down of nuclear plants could seriously affect plant availability in MAIN, MAAC, MAPP, SERC, NPCC and WSCC, thus reducing the adequacy of electric supplies for these regions.

Regions or systems with a higher proportion of aging plants may suffer a decline in availability if, as expected, the older plants require more frequent maintenance. In ECAR, MAIN, NPCC, and SPP more than a quarter of all installed capacity in 1995 will consist of fossil-fired plants that are more than 30 years old. These "geriatric plants" may, however, prove to be valuable resources as some may be very cost-effective peaking units and others may be suitable candidates for life-extending refurbishment to provide power at lower costs than equivalent new plants. Some nuclear plants may face more frequent operating restrictions as they age.

Bulk power purchases may be an attractive alternative to building new utility capacity for systems with concerns over supply adequacy and/or reliability. The existence of a range of competitive suppliers and the availability of transmission services to move the power would seemingly offer benefits to these systems and regions. If the benefits offered are perceived to outweigh potential risks, it is likely that utilities and regulators would be receptive to proposals for a more competitive industry structure.

Utilities in area.. without surplus capacity are likely to be less resistant to competitive supplies both because of the need for reliable least-cost capacity and because the competition covers increments of new supply and does not directly threaten the loss of existing markets. There also will be a regional incentive to work out transmission access and other difficulties. If, however, a region does not need capacity but in fact has a surplus of generating capacity, expanded competition could have potentially adverse consequences for traditional regulated utilities and their ratepayers in loss of market share, bypass, and additional purchase obligations. On the other hand, competitive markets might provide a mechanism to sell some of their existing surplus power and capacity.

Transmission Access

Transmission access considerations include the terms (including price) under which a party will be permitted to move power over the grid and the conditions that influence the availability and adequacy of the transmission system.

Although theoretically possible because the necessary physical connections are in place, it is not always possible in practice to move large amounts of bulk power between any two points in the United States over the existing transmission system. This situation is not likely to change in the near future for several reasons. First, available transmission capacity is limited and much of this is committed under long-term contract. The existing transmission lines in most areas of the country are already heavily loaded with firm and economy energy transactions according to utility industry sources. Second, the United States is not physically integrated on a single grid. The lack of extensive interties between the three separate interconnections (not to mention Alaska and Hawaii) will limit the extent of any competitive markets that may evolve. This means, for example, that surplus power from Texas (ERCOT) will not easily be able to compete in markets in Arkansas, Louisiana, and Oklahoma (SPP-SERC), or in New Mexico-Colorado (WSCC). Third, transmission capacity usually cannot be added quickly. It takes time to design, site, and build new or expanded transmission facilities, and sometimes local opposition is intense. In extreme cases, it can take several years or more to put a new line in place once a need and cost effectiveness have been clearly established. Finally, the as yet unestimated costs of building and maintaining national or regional grids with ample excess transmission capacity to accommodate a broader range of potential power transfers are likely to be high, and perhaps unnecessary for most needs.

In areas where the transmission system is already heavily loaded, it has been asserted that at times desirable bulk power transactions could not be accommodated without exceeding minimum system reliability operating guidelines. Comprehensive assessments of the locations and the extent of such constraints have not been undertaken, nor are any estimates available of the potential savings foregone. A frequently cited example of transmission constraints is that surplus coal-fired power from the Midwest cannot easily move to Northeast and Southeast utilities that may be looking for additional supplies because of transmission constraints or bottlenecks in ECAR and MAAC. These constraints have been partially attributable to the heavy use of lines under long-term ''firm" energy commitments, power pool transactions, and parallel flows from Canadian-U.S. transfers in NPCC.

Even if transmission capacity is available, without some sort of provision for assuring transmission access, some line owners may be unwilling to open up the grid to wheel power for others. The possible reasons for refusals are many and include: to reserve available capacity for the line owner's opportunities to sell or buy power at attractive prices; to maintain redundant transtnission capacity to enhance system reliability and flexibility; to restrict access to its market area and customers by actual or potential competitors; and/or an unwillingness to undertake the burdens of additional regulatory, accounting, and operating requirements that may be involved in opening up the system. Some analysts note that lack of effective economic incentives for wheeling services or adding transmission capacity under the existing institutional and regulatory treatment of wheeling arrangements is a major impediment to increasing transmission access.[37]

Existing regional transmission relationships among utilities through power pools, coordination agreements, and Federal power marketing systems could help the development of an effective transmission access system. These ongoing relationships could become the foundations for the essential institutional structure, precedents, and arrangements for executing wheeling transactions to move power and make deals. Without the necessary institutional protections, greater competitive pressures and the attractiveness of profitable off-system bulk power sales could lessen the characteristic cooperation of joint operations and power pools. Growing rivalry among regional utilities could discourage sharing of information and generating and transmission resources, adversely affecting reliability and power pool operations. Competitive pressures could yield lower capacity margins and reduced maintenance of facilities in an effort to cut costs. But, at the same time, generators would continue to share a common direct interest in maintaining optimum system operations, which perhaps could counter behavior that might imperil current reliability levels.

The extent to which interregional or intersystem transmission access or availability will become more or less critical in the future cannot be predicted with any certainty. The existing demand for and interest in transmission services are the result of several conditions:

- current capacity surpluses and shortages,
- differences in bulk power prices/costs,
- relative locations of load centers and generating plants,
- availability of and eligibility for wheeling services, and
- industry structure and practices.

Because many of the above conditions can change over time, a significant share of the present demand for transmission services could be transitory and could disappear in a shorter time than that needed to

[37] National Regulatory Research Institute, Some *Economic Principles for Pricing Wheeled Power* (NRRI-87-7) August 1987; National Regulatory Research Institute, *Non-Technical Impediments to Power Transfers* (NRRI-87-8) September 1987.

Photo credit: *Casazza, Schultz &* Asao@ates, lnc.

A high-voltage transmission corridor

plan for and recover investments in additional transmission capacity.

For example, if new generating sources locate close to load centers and within the local transmission grid or service areas of customer utilities, the need for some long-distance firm and economy power transfers would be reduced and the transmission system could at least in part revert to its role as a means of providing emergency power. There is some evidence that utilities are giving preference to generating capacity additions that reduce demands on the transmission system.[38]

Changes in fuel costs could eliminate much of the bulk power price differentials driving many wheeling transactions. For example, when oil prices were very high, a transmission interface was built to tie the surplus coal-fired generation in the Southern Company system to oil and gas-fired utilities in Florida. With lower oil prices and new generating capacity on line, power purchases from the Southern Company are sharply down and the interface is loaded far below its previous levels (one of the very few examples of acknowledged surplus capacity).

While some portion of transmission demand could be transitory, the electric power industry's

[38] Texas Utilities is adding combustion turbines to its system at remote system points rather than at a central location in order to avoid the need for additional transmission, *Electrical World, tel. 202, No. 7,* July 1988, p. 31. Location has frequently been acknowledged as an important "nonprice" factor in evaluating competing bids.

structure and practices assure that the extensive transmission network will continue to be needed under various future scenarios. Joint operations and power pooling arrangements are motivated by reliability and economic concerns. Strong transmission networks are needed to move power to load centers from distant generating sites. Long-term contracts and other arrangements are in place to move power from coal plants in Arizona and New Mexico west to California, and from hydroelectric projects in Quebec south to New England and New York. Other agreements exist to take advantage of seasonal load differences, such as the current and planned 1ong-term power contracts to move power south from the Pacific Northwest in summer and north from California in winter. These transactions will be of concern not only to the parties involved but also to other utilities on the interconnected systems because of their inevitable influence on the grid.

Many utilities, particularly in the public sector, rely on bulk power purchases to supply all or part of their requirements. These utilities (or distribution-only utilities under some competitive scenarios) would still seek lowest cost supplies for their customers and will press for wheeling services so that they are not necessarily tied to a single monopoly supplier.

Transmission concerns will remain even if the extent of economy transfers diminishes, growing demand absorbs surplus capacity, and new generating capacity is built. Utilities, generators, and customers will share a common interest in the reliability and security of electric power supplies. New patterns of bulk power transactions and the entrance of nontraditional power suppliers have accelerated the breakdown of the old model of the regionally isolated integrated system generating and transmitting power solely within its exclusive territory to serve the needs of (captive) customers.

The Regulatory Environment

The regulatory environment created by State and Federal policies could advance or hinder a shift to a more open, competitive electric power industry. A number of States have already allowed utilities under their jurisdiction to use competitive bidding or negotiation to secure new power supplies and to establish avoided costs—thus advancing competition.[39] The Federal Energy Regulatory Commission (FERC) has proposed rules to allow the use of competitive bidding to set PURPA avoided-cost capacity payments and to encourage the entry of independent power producers. Both of these measures are intended to encourage competition. However, some State regulators have criticized the FERC proposals as actually hampering and delaying the growth of competition by preempting State initiatives in the area and requiring extensive changes to many State regulatory programs. State regulators and others have criticized the lack of explicit FERC guidance or rulemaking on transmission access and pricing issues as constraining the growth of competitive markets by shutting out potential buyers and sellers.

Some options for reform of the existing system could impose additional burdens on regulators, consumers, and State jurisdictional utilities (such as, for example, the proapproval process in scenario 1 and the needs determination and bidding programs of scenario 3). The increased involvement of regulatory agencies is a necessary component of the reforms intended to avoid the risks of regulatory disallowance under existing law.

New Federal initiatives could also diminish the effectiveness of State and local programs in consumer representation and protection, siting, alternative energy technologies, conservation, and energy efficiency.

The most significant area of regulatory policy is establishing the appropriate and respective roles of State and Federal regulators. This task has been made more difficult by recent FERC actions and

[39] At least 24 States have adopted or are developing variations of competitive procurement programs for some or all of regulated utilities power needs. Among the Stales that have adopted bidding programs are: Virginia, Connecticut, Maine, Massachusetts, New York, California, Texas, and Colorado. Some have imposed wheeling requirements on instate utilities m conjunction with PURPA implementation. Many States have already moved to correct early difficulties with PURPA avoided costs. Slates' anticipatory oversight of utilities' generation and transmission resource planning increasingly encourage consideration of competitive and regional needs. See Mary Nagelhout, ''Competitive Bidding in Electric Power Procurement: A Survey of State Action," *Public Utilities Fortnightly*, vol. 121, No. 6, Mar 17, 1988, pp. 41-45.

U.S. Supreme Court decisions.[40] The split jurisdiction over utility regulation has long been an area of tension and source of uncertainty. Recent State efforts might be stymied by Federal preemption of their regulatory programs if existing initiatives were not grandmothered under new Federal rules. The limited State jurisdiction over transmission access also tends to undercut State implementation of competitive strategies. As noted in chapter 3, it is possible under some alternatives to delegate to the States certain responsibilities for transmission jurisdiction now resident at FERC. This could perhaps be coupled with a right of appeal to FERC or the Federal courts. One advantage of such an arrangement is to move decisions on system use, retail wheeling, and prudence back to those who must weigh competing local interests in approving resource plans, siting, and retail rates. In cases involving interstate transactions, there might be some mechanism for consultations between States or referrals to FERC. This could foster more comprehensive State and regional cooperation on transmission issues.

The confidence of the affected parties in the decisions of regulatory authorities or in the mechanisms that substitute for the operations of the regulatory system will be very important for the success of initiatives for a more competitive system. If, for example, consumers believe that their interests are not adequately protected, or perceive that utilities or independent power producers are unduly enriched by the new arrangements, their political opposition to the alternative may well doom its long-run success.

Competitive Environment

The competitive environment in a utility system or region will be a major influence in how rapidly and successfully any shift toward a market-based sector will proceed. There are many tangible and intangible factors that will shape the competitive environment, and these will likely be tied to site-specific and regional conditions,

The existing power system infrastructure and institutional arrangements could either help or hinder market entry and competition in a State or region. If there are one or more dominant utilities with control of critical facilities, such as low-cost generating facilities, distribution companies, or transmission systems, new entrants could be deterred from competing in that market area. If most bulk power supplies are already committed under long-term contracts or there is a surplus of existing low-cost power, opportunities to compete for new power supplies could be limited. But a demand for power or a specialized niche for potential competitors can create market opportunities that attract competitors. In the Northeast, with the support of State regulatory commissions, many utilities are actively soliciting bids for capacity increments from QFs and other suppliers, In four States (Connecticut, Maine, Massachusetts, and Virginia) that have completed competitive solicitations, the bids far exceeded the amount of power sought.

The availability of sufficient transmission capacity to support the growth of a competitive regional bulk power market is also important. Mandatory wheeling authority would not be of much help to guarantee transmission access if the system is already fully loaded.

Impacts on Retail Customers

Impacts on retail customers will ultimately determine the acceptability of any electric power industry structure and its longevity. The most significant effects will be in retail electricity prices and changes in reliability or quality of utility services. Local experiences and perceptions will be different. In some regions, a move to a more competitive structure may be perceived as a net benefit, in others it may become the focus of all dissatisfaction with electric power system operations and prices. If the latter is the case, consumers will pressure their elected officials to reform the system.

In weighing various proposals for change, regulators will have to deal with a range of equity considerations in the areas of public service and accountability, distribution of costs and benefits, and system reliability. Often there will not be adequate information available to respond fully to

[40] The recent expansion of Federal preemption is seen in the FERC decision in Orange and Rockland Utilities, Inc., 92 PUR 4th 1988, and the U.S. Supreme Court's decision in *Mississippi Power& Light Co v. Mississippi ex rel. Moore Attorney General of Mississippi et al , No. 86-1970,* June 24, 1988.

these concerns and the determination will rest on the best judgment of decisionmakers.

OTA SCENARIOS AND REGIONAL IMPLEMENTATION

The impacts of OTA's scenarios, as with similar proposals, will depend on the characteristics of the individual utility systems and State regulatory bodies. The detail required to analyze and predict these potential impacts lies well beyond the scope of OTA's review of the technical feasibility of implementing the scenarios. Nevertheless, the local impacts will create significant considerations for policy makers. It is notable that none of these impacts has been examined in any systematic, comprehensive way in the various proposals that OTA used in developing these scenarios.[41] Even FERC did not provide any substantive analysis of the potential impacts of its recent Notice of Proposed Rulemaking (NOPR) beyond its assumed "worst case" environmental impacts analysis, which was driven by arbitrary assumptions on fuel use, technology choice, and generation by independent power producers.[42] A further confounding problem in ascertaining potential impacts is uncertainty over how wheeling transactions will be priced. Although transmission pricing was outside the scope of this assessment of technical feasibility, it will be highly determinative in shaping the extent of and participation in competitive markets under all scenarios.

Scenario 1

Scenario 1 would modify the existing State regulatory programs to require State proapproval for construction of new utility capacity with prudence determinations at strategic milestones in each project.[43] The scenario would also include Federal and State regulatory changes to remove some of the problems encountered in early implementation of PURPA, such as limiting the categories of eligible facilities and bringing PURPA energy and capacity payments more into line with utilities' actual avoided costs.

Under this scenario. as in others, major impacts will be local and utility-specific. The reduced regulatory risk of disallowance may provide an incentive to reluctant utilities to identify and construct needed capacity earlier than they might otherwise plan under a risk aversion strategy. It is not known how many utilities, if any, would fall into this category. where they are located, and how much needed capacity would be affected.

Scenario 1 would affect the regulatory systems in all States,[44] although the potential disruption of State programs may be tempered somewhat by the fact that many States already have incorporated elements of scenario 1 in their State programs.[45] These key elements include prior review and certification of need for new capacity and review and approval of utilities' resource plans. The existing precedents of regulatory standards for prudence could be applied in a periodic milestone review. Most States have allowed recovery of prudent investment on abandoned plants.

Although no State has adopted the equivalent of scenario 1, Massachusetts recently established a proapproval process for new non-QF capacity that would, among other things, set the allowed rate of

41 One exception to the general lack of detailed analysis of the more popular schemes for change is found in the review of various deregulation scenarios by Paul L. Joskow and Richard Schmalensee, *Markets for power" An Analysis of Electrical Utility Deregulation*, (Cambridge, MA: The MIT press. 1983). They too were somewhat hampered by the unavailability of data with which to conduct any detailed analysis.

42 Federal Energy Regulatory Commission, Draft Environmental Impact Statement on Regulations Governing Independent Power Producers (RM88-4-000) and Regulations Governing Bidding Programs (RM88-5-000), June 1988.

43 It is conceivable that Federal legislation (like PURPA) could require States to adopt a proapproval structure within FERC guidelines, but leave the details of implementation to the States. Legislation could also require that FERC follow State planning and preapproval processes or confer with State regulators in considering rate requests and rates of return for FERC jurisdictional utilities.

44 Except perhaps Nebraska which relies solely on public power and has no Statewide ratesetting body. Texas, Alaska, and Hawaii are also Stales where the impacts on existing regulatory programs are uncertain because they are not generally connected to the rest of the interstate electric power systems and thus are not fully under FERC jurisdiction. The changes in PURPA rules would, however, affect State PURPA regulatory programs and unregulated utilities.

45 See discussion in ch. 3 and "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," prepared by staff members of the Public Utilities Commission of the State of Ohio and of the West Virginia Public Service Commission, OTA contractor report, July 1988 (hereafter State Government Survey responses).

return in advance of project construction.[46] More than half the States have a least-cost planning program in place or under development. Most States require utilities to submit long-range plans for generation and transmission requirements.[47] More than 24 States already have approved bidding programs and others currently are considering them. Most State programs provide for regulatory review and approval of resultant utility contracts. (Some specifically defer decisions over the prudence of the power purchase arrangement until the time of power delivery, however.)

To accommodate this multi-stage regulatory process, State agencies will have to increase staff and budgets or divert resources from other activities. Utilities also would see some increase in their regulatory activities. The greatest regulatory impacts would be felt in States in the West and Southeast that typically have State regulatory programs with a more traditional, reactive approach to ratemaking and that do not have much involvement in anticipatory oversight or review of utilities' resource planning.[48]

The scenario would give States the flexibility to allow experiments in competition for bulk power supplies as they wished. Under scenario 1, transmission access remains largely voluntary under existing law. Depending on whether or not FERC addresses the issue. the lack of effective transmission access remedies could hinder further development of competitive markets.

The fine-tuning of PURPA avoided cost and QF eligibility requirements might reduce avoided cost payments and the amount of available QF power in States such as California, Texas, and Colorado where high avoided cost rates or high QF capacity potential have provided an initial abundance of QFs seeking contracts with local utilities.

Scenario 2

Scenario 2 would expand QF eligibility criteria under PURPA and provide greater access to wheeling services for wholesale and retail customers. This scenario could have significant local impacts. On the one hand, scenario 2 could expand the current abundance of QF power in some regions. On the other hand, the influx of additional QF power could drive QF avoided cost payments down, providing some financial relief to host utilities and their ratepayers. (This would be of only limited value if high cost QF capacity is already under long- term, fixed-price contracts.) Availability of wheeling could allow QFs, independent power producers (IPPs), and utilities greater access to potential customers for their power and could reduce the purchase obligations of some host utilities. The wheeling of QF power from the host utility's service area to utilities with higher avoided cost payments, who must then purchase the offered power, is an option under existing law, but there is no mandatory transmission access under PURPA.

The scenario could favor large fossil-fueled QFs and IPPs that enjoy some economies of scale and discourage the smaller alternative generating technologies originally targeted in PURPA, unless the smaller facilities could match competitive prices. It could also result in different local environmental impacts than would arise from the plant mix under the existing system.[49]

Scenario 2 would require Federal legislation and complementary changes in State regulatory systems. If States were given authority over retail wheeling requests, States could make the public interest determinations associated with problems of bypass and interclass allocations of system costs in the ratebase. The availability of retail wheeling would mean that utility systems with higher retail prices than other systems in their regions could see increased vulnerability to bypass, and loss of cus-

46 "A Real Massachusetts Miracle," *Public Utilities Fortnightly*, vol. 121, No. 15, July 21, 1988, pp. 6-7; Massachusetts Department of Public Utilities, "pricing and Rate-making Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities," D.P.U. 86-36-C, May 12, 1988.

47 State Government Survey Responses, supra note 45.

48 Ibid.

49 The FERC draft EIS assumes that expanded participation of IPPs will displace QF capacity (coal, oil, gas, and was(c), See DEIS ch. 4, supra note 42. See also the discussion inch. 7 of this report.

tomer load and revenues.[50] Under scenario 2 bypass could be exacerbated not only among retail customers, but also, more significantly, among wholesale requirements customers.

The additional transmission incentives under scenario 2 could include more explicit consideration of State and regional transmission needs in energy planning and ratemaking decisions. State or regional entities might offer to mediate arrangements for compensation and/or mitigation with affected property owners and localities, for example, to assist in resolving conflicts that might hamper needed transmission facilities. Regulators would be more involved in oversight of transmission. Federal and State regulators might encourage a greater willingness for voluntary provision of transmission services through experiments in pricing wheeling transactions and incentives for expansion of transmission capability.

If transmission prices and interconnection conditions are not so onerous as to render transmission access provisions ineffective, the stresses on already heavily loaded transmission systems will increase and create even more pressure for additional capacity. If scenario 2 results in a large net increase in system demands, areas in ECAR, MAAC, NPCC, ERCOT, and WSCC are likely to see the most serious effects. Scenario 2 could result in utilities being ordered by States or FERC to construct additional transmission capacity to provide wheeling services. Scenario 2 would not preempt local and State authority over siting approval, however. This result would also occur under scenarios 3, 4, and 5.

Scenario 3

Scenario 3 is similar in some aspects to FERC's competitive bidding NOPR, but requires that all States use competitive bidding and also includes mandatory wheeling authority.[51] The responsibilities and administrative burdens carried by State regulatory agencies would increase markedly under this scenario, most noticeably in States with more modest traditional regulatory programs and in those States with high growth in electricity demand. FERC'S administrative caseload would also increase. Under scenario 3, regulatory proceedings would probably involve more parties as competitive power suppliers joined utilities, regulators, and consumers in needs determinations and in the review and awarding of new source contracts.

The participation in all source competitive bidding in areas needing capacity would depend on how the solicitation is structured and the weighting of nonprice considerations. In particular, many traditional QF cogenerators and small power producers could be discouraged from competing in a highly structured bidding program against larger and more sophisticated IPPs and utility affiliates. Similarly, conditions such as wheeling requirements or protections against self-dealing could constrain utility participation both inside and outside their service territories. In its draft Environmental Impact Statement (EIS), FERC projects that its proposed rulemakings on competitive bidding and LPPs might result in significant displacement of incremental utility and" QF capacity, including some renewable energy technologies. Additionally, the draft EIS concludes that the locations of new generating plants and transmission loading patterns could be shifted among various regions.[52] It also expresses doubt that real impacts would be felt until the mid to late 1990s at the earliest because of existing capacity abundance. In the limited experiences with competitive solicitations that have taken place, there has been a mix of IPPs, utility affiliates, and cogeneration projects proposed, but it is still too early to determine what would happen if all source competitive bidding were to replace the existing alternatives of utility construction, negotiated purchases, and required QF purchases.[53]

The availability of wheeling might encourage wholesale requirements customers to seek alternative power suppliers, possibly exacerbating the problems of ''stranded investment" and bypass on

[50] Many high-cost utilities already face problems because of conservation, self-generation, and or plant-closings. Wheeling, and in particular retail wheeling, would give their customers another means of avoiding the high prices of local utilities. This problem would exist under scenario 3, but without the additional strains of retail wheeling.

[51] It has been argued that the effective result of the three FERC NOPRs is to impose all source competitive bidding on States, since compliance with requirements for administrative avoided costs would be unduly burdensome so that regulators and utilities would rely on bidding.

[52] DEIS, supra note 42, ch. 4.

[53] See discussion in ch. 5 on the California, Maine, and Virginia competitive bidding systems and in ch. 7 on the Massachusetts bidding system,

high-cost utility systems. The departure of existing customers could leave the remaining ratepayers with the burden of paying for a system that is larger than required unless regulators shifted a sizable portion of the losses to the utility and its shareholders. Because there is no retail wheeling under scenario 3, its impacts on the transmission system might be less than those of scenario 2, at least initially. More lines might eventually be built in scenario 3 than in scenarios 1 or 2 to support the competitive system and to open up new markets as the industry shifts away from the old model of self-sufficient integrated regional utilities tied together for enhanced reliability.

According to some proponents, the expanded competitive market and availability of wheeling could theoretically dampen the discrepancies in the prices of power within and among regions as lower-priced power is bid up and higher-cost/higher-priced producers are forced to cut costs or be displaced. Because electric power would typically be committed under long-term contracts, it is not clear how long this will take and how great the impacts will be on consumers and electric supplies over the period needed for market forces to accomplish this result.

Scenario 3's success will in large part depend on local characteristics. The early impacts and experiences will come in areas that need generating capacity from 1995 through **2000.** In some areas, however, the power solicitations might not draw enough competitive interest to rely solely on bidding results to set power prices. Reliance on competitive awards might make some areas heavily dependent on NUG power with potentially greater risks of less flexibility in control of generating resources as discussed in chapter 5. Whether this results in lowered reliability for the power system will depend on the adequacy of alternative protective arrangements to compensate for changes in the resource base and system operations. Utilities could offset at least some increased risk by building or contracting for higher levels of reserves than they would under a traditional cost of service system.

Over the long term (20 to 30 years and more), scenario 3 would move the industry toward a competitive generation sector within a regulated and integrated utility structure. This evolving structure will eventually raise some of the same issues presented by scenario 4 about the preservation of competition as an alternative to traditional cost-of-service regulation/pricing, fairness to ratepayers in treatment of proceeds from use of ratebased facilities and intangible assets in promoting competitive activities, and the long-term bargaining power and viability of regulated transmission and distribution sectors.

Of concern under both scenarios 3 and 4 is that some regions may not initially have enough viable suppliers to sustain a competitive market that could be relied upon to set prices in lieu of regulation. This possibility is created in large part by the existing patterns of regulated utility holdings and franchise territories.[54] This may be a particular problem in regions where very large integrated private utilities and holding company systems occupy strategic and dominant positions in ownership of generation and transmission resources. New entrants could be intimidated in situations where utility control of transmission facilities and the uncertainty of gaining a wheeling order combine to restrict access to potential customers.

Scenario 4

Scenario 4 would create an all competitive generating sector over a moderately short transition period (of 5 to 10 years for example as compared to the evolutionary approach in scenario 3). New segregated generating subsidiaries or spinoffs of existing integrated utility companies would initially control an overwhelming share of generation resources under the new system. All generators would be able to sell power and would be eligible for transmission services. The transmission and distribution segments would consist of the segregated transmission and distribution operations of formerly integrated utilities and wholesale/requirements customers. Transmission and distribution utilities would remain regulated and would retain an obligation to serve. There are a number of major uncertainties in how scenario 4 will be implemented that will strongly influence its outcome. The major regional impacts/uncertainties of scenario 4 focus on the viability of competition and the role of State regulation.

[54] See Joskow and Schmalensee, supra note 41.

Under scenario 4 there is the possibility that newly independent local generators will use access to transmission to flee existing service territories for more lucrative markets, leaving ratepayers and distribution utilities without adequate suppIies and facing substantial rate increases.

The existing regulated industry structure will not provide an initial level playing field for creating a new competitive industry. Existing franchise territories and generating resources as well as the considerable financial strengths of some utilities will create competitive advantages. Other utilities may start at a competitive disadvantage. As a result higher-cost producers that once enjoyed the protection of their government-franchised territories could be driven from business under a market-based system, and there could be a marked trend toward consolidation in the generating sector. Some transmission and distribution utilities would also become candidates for mergers or acquisitions.

Regions and States with extensive existing transmission arrangements through power pools, coordination agreements, and Federal power marketing systems might have an advantage in creating the necessary institutional infrastructure for separate transmission utilities under scenario 4.

If all bulk power supply arrangements fall under exclusive Federal jurisdiction because they are ‘‘sales for resale, ” State and local regulators with jurisdiction over distribution companies face the loss of any effective influence over generators, thus imperiling the adequacy of their regulation of transmission and distribution. New Federal and State policies may be needed to protect the interests of ratepayers and the public under a changed market and regulatory structure.

Scenario 4 has a very high potential for substantial impacts on consumer electric prices in many regions, if the transfer from regulated rate-based assets and service territories to unregulated competitive generators and open markets is not handled equitably. In the transition, utilities could gain windfalls from the sale of low-cost power produced by older, depreciated plants or from the sale of those plants. The profits could be transferred to or retained by their new unregulated generating companies. Policymakers could limit this potential by requiring that rate-based assets from the predecessor integrated utility be transferred at either replacement or market cost with the proceeds going to the successor regulated distribution utility and its ratepayers. Additionally, communities and ratepayers with low retail rates may lose many of the financial benefits of past sound and prudent utility management and regulatory oversight as the owners of newly liberated generating plants rush to sell their power at the highest price.

Scenario 5

Scenario ***5*** also involves the dramatic revamping of the electric power industry and the transfer of billions of dollars in ratebase assets; it differs from scenario 4 in two respects. First it would involve the actual disintegration and divestiture of utility assets into separate legal and financial entities, while preserving the ongoing viability of integrated operational functions through the creation of new entities and new institutional arrangements. Second, its common earner transmission entities would provide wheeling services for retail customers.

Scenario 5 shares almost all of the concerns over industry concentration, preservation of competition, and reliability as scenario 4 plus the additional challenges and complications of creating a common-carrier transmission system that will adequately serve the needs of utility and nonutility customers.

To be an effective entity, the common carrier transmission company would likely be involved in multistate operations and would thus create additional challenges to Federal and State regulation and oversight of rates, planning, and siting activities.

REGIONAL PROFILES[55]

The East Central Area Reliability Region (ECAR)

Voting membership in ECAR is open to those members that meet three criteria. They must: own an electric utility system engaged in the generation, transmission, and sale of power in the region; operate in synchronism with two or more members in the Agreement; and have a significant impact on reliability. Nonvoting members are those systems that do not have a significant impact upon reliability but share concerns relating to the reliability of bulk power supply.[56]

Fuel Use

ECAR is heavily reliant on coal and is expected to continue this reliance well into the 1990s. Nuclear is projected to increase slightly its share of total electricity production from 8.7 percent of the total in 1988 to 9.3 percent in 1997.

Capacity

According to NERC, installed capacity will increase by about 7,100 MW by 1997. only three major unit additions, totaling 3,095 MW, are scheduled during the 1988-1997 period. Very little new capacity is scheduled for operation after summer 1991.

Average annual growth for the period 1988 to 1997 is projected to be 1.6 percent for summer and 1.7 percent for winter. ECAR is expected to be summer peaking throughout the period.

Transmission

ECAR has an extensive system of intrasystem, intraregional, and interregional connections ranging from 115 kV up to 765 kV. According to NERC, current plans for the 1988-97 period call for an additional 100 miles of 500 kV and 200 miles of 345 kV transmission lines.

Transmission networks in the eastern part of the region provide connections with Southeastern and Northeastern areas of the United States. Networks in the western part of the region provide interregional connections with MAiN. These ties result in substantial interregional power transfer capacity. The American Electric Power Company owns about 40 percent of the high-voltage capacity in ECAR.[57]

In recent years, ECAR'S extensive transmission network has experienced numerous large-scale economy transfers, which are created by fuel-cost differentials. These intraregional and interregional economy transfers have caused power flow patterns that were not anticipated when the system was planned. To continually ensure transmission system reliability, ECAR and neighboring regions conduct performance evaluations before each summer and winter peak load season and annually.

Bulk Power Transactions

Within ECAR, bulk power transactions to other regions, especially the PJM Interconnection and Virginia are based on load diversity and fuel cost differences. American Electric Power and Allegheny Power Systems, two large holding companies in the region, dominate sales transactions[58] and control much of the transmission grid. ECAR utilities surveyed by NGA reported the smallest amount of bulk power purchases-*3 contracts* for 188 MW. On the other hand, ECAR utilities reported contracts to sell about 3,6(M) MW, second only to SERC in terms of sales. The length of the contracts ranged from 6 months to *3 years.*

Coordination

Coordination in this region ranges from tight holding company pods, to less integrated pools, to individual utilities that do little coordination. Generally, the region's holding companies and power pools coordinate very

.

Reliability

According to NERC, the existing and planned electric power supply in the ECAR region will satisfy the region's reliability criteria if generating equipment continues to be available at present levels and load and capacity conditions are as projected. Even a small decline in generating equipment availability and/or a slight increase in load

[55]Regional profiles are based primarily on NERC documents, unless otherwise noted.

[56]"Reliability Council Survey Responses," supra note 2, p. 5.

[57]FERC, *Power Pooling,* December 1981. p. 96.

[58]DOE, *Interutility Bulk Power Transactions . Descriptions,* &O&S, *and Data.* October 1983, p. 41.

[59]FERC, supra note 57, p. 97.

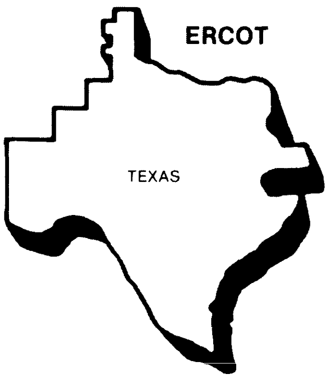
growth could quickly reduce the future power system reliability to unacceptable levels.

NERC expects capacity margins to decrease over the next decade, from a current level of 23 percent. As capacity margins decrease, generating units will be utilized more intensely. Placing greater demand on these units may be increasingly difficult as plants get older. By 1997,42 percent of all generating units in this region will be 30 or more years old.

Furthermore, because of its dependence on coal to generate electricity, ECAR is especially vulnerable to acid rain legislation. Strong new pollution control equipment requirements could affect the availability of coal-fired generating capacity in the region, possibly reducing reliability.

Electric Reliability Council of Texas (ERCOT)

Membership in ERCOT is open to any entity that owns, controls, and operates an electric power system in Texas. Members' votes are weighted on the basis of the average number of kWh handled through the intrastate system for the preceding 3 calendar years. Each entity is assured at least one vote.[60]



Fuel Use

ERCOT utilities rely heavily on coal and gas to generate electricity. NERC projects that by 1997 coal will increase its share to 44 percent, and gas use will decrease from a 45 percent share to a 33 percent share. Nuclear will account for about 11 percent of the total.

Capacity

ERCOT is expected to increase its installed capacity by about 12,500 MW between 1988 and 1997. Member utilities indicate an average annual growth rate of 2.4 percent (summer peak) for this period, which is a reduction from the 3.9 percent rate projected in 1987. Winter peak demand is forecast to grow at 3.2 percent for the same period.

Transmission

in recent years, ERCOT has experienced increases in both firm and economy energy transfers. At the same time, transmission additions have not come on line as quickly as anticipated. Moreover, planned additions have been reduced. ERCOT expects to install about 931 miles of 345 kV lines during the next 10 years. This figure represents a 29 percent reduction from the 1()-year projections made in 1987. In 1987, ERCOT had 6,871 circuit miles of 230kV and above transmission lines.

Bulk Power Transactions

Because ERCOT utilities are isolated from the Eastern and Western Interconnected Systems, bulk power transactions based on generation diversity are 1imited. Even so, the average ERCOT utility has about the same volume of transactions as does the average L'. S. utility, according to DOE.[61] This may be due, in part, to the wheeling of QF power from large cogenerators in the region, The NGA survey found that ERCOT utilities had contracts to buy 1,760 MW and sell 3,200 MW.

Coordination

The Texas Interconnected System (TIS) is the umbrella coordinating group in ERCOT. Its primary focus is on bulk power supply reliability, through coordinated planning and operation. Bilateral agreements form the core of existing coordination.[62]

Reliability

NERC expects planned capacity resources to be adequate during the 1988-97 period. The projected capacity margins range from 21.3 percent in 1988 to a high of 23.6 percent in 1990 and to a low of' 16.4 percent in 1996. These margins exceed The planning guidelines adopted by the region. Nonutility generation will supplement ERCOT's short- and long-term capacity needs.

On the other hand, transmission system reliability is of some concern to ERCOT. Increases In economy and firm interchanges have placed a strain on portions of the system. NERC expects further increases in transmission system usage to continue because of wheeling for utilities and nonutility generators. According to NERC, during 1986 wheeling of firm electric power amounted to 2,148 MW of capacity —5.5 percent of regional peak demand.

Contributing to this situation is the fact that transmission improvements have not proceeded as planned. One major concern is the recent decision of the ***Austin City***

60 "Reliability Council Survey Response," supra note 2, p. 6.

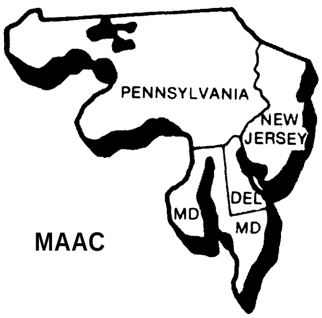
61 DOE, supra note 58, p. 42.

62 FERC, supra note 57, p. 132.

Council to cancel construction of several **345** kV lines that were originally scheduled for service in 1988. Concern about possible health effects of electric and magnetic fields was one of the reasons given by the Council for canceling construction. In addition, the Texas Public Utility Commission rejected the proposed Salem-Zenith interconnection. The decision is currently being appealed to the courts.

Another reliability issue is the region's reliance on natural gas as a boiler fuel. The long-term availability and price of this fuel will impact reliability in the future, but to a lesser extent than in other areas as Texas is a major gas producer.

Mid-Atlantic Area Council (MAAC)



MAAC voting members must meet three criteria. They must be directly interconnected and operated in parallel with one or more MAAC members; their operations must significantly impact the reliability of the bulk electric supply systems of MAAC members; and they must abide by the rules of the Executive Board. Nonvoting members-may include any municipal systems, rural electric cooperatives, or small investor-owned utilities that are served by MAAC members and agree to the principles of the MAAC agreement.[63]

Fuel Use

MAAC relies on coal and nuclear-powered generation. By 1997, NERC indicates that coal's share of electricity production will decrease, while nuclear, oil, and hydro use will remain essentially the same.

Capacity

From 1988 to 1997, installed capacity (summer peak) in this region is expected to increase by about 6,730 MW. Included in this total are about 2,860 MW of nonutility generation and other small unit additions. Also during this same period, 830 MW of existing generation will be retired or derated.

Summer peak demand is expected to grow annually by 1.3 percent, while winter peak demand increases by 2.0 percent annually. MAAC has traditionally been summer peaking, but will convert to winter peaking after the turn of the century if the present trend continues.

Transmission

The MAAC transmission network consists of about 6,500 circuit miles. From 1988 to 1997, an additional 110 miles of 500 kV lines and 400 miles of 230 kV lines are planned for the region. According to NERC's 1988 Reliability Assessment, transmission capability is a concern in MAAC. The increasing use of transmission lines has resulted in heavy loadings on critical lines affecting interregional transfer capability.

NERC reliability reviews indicate that the primary transmission constraint in the area is the major west-to-east transmission path. During 1987, the PJM system was loaded to the limit of its west-to-east transfer capability %.8 percent of the time.[64]

A 1984-85 study by ECAR/MAAC for DOE cited loop flow from the New York Power Pool and New England Power Pool and weaknesses in the MAAC system and eastern ECAR as limiting the potential for the west-to-east transfer of coal-fired power to back out oil-fired generation in the East. However, the study asserted that the existing transmission system already provided about 90 percent of the economic benefits that could be realized if the existing transfer capacity were doubled.[65]

An increase in nuclear capacity in recent years and the declining differential in oil/gas and coal prices have reduced the overall transfer of economy energy from regions west of MAAC, particularly ECAR. But, internal transfers of energy along the west-to-east transmission path have remained high. This is especially true during daily peak load periods. Because transmission flow patterns in this region are very dependent on oil price fluctuations, future changes in flow patterns will be difficult to predict. Relatively high oil prices would tend to increase the need for west-to-east transfers.[66]

Bulk Power Transactions

MAAC utilities report a relatively low volume of transactions, according to DOE. There may be several reasons for this low volume:

1. MAAC's transmission capacity may limit transactions even when generating capacity is available;

63" Reliability Council Survey Responses, " supra note 2, p. 6.

64OTA contractor report, "Case Studies on Increasing Transmission Access. " Casazza, Schultz& Associates, Mar. 18, 1988, Appendix A, p. A-1,

65"ECAR-MAAC Interregional Power Transfer," as reported in OTA contractor report, Ohio Public Utilities Commission, supra note 2, p, 302.

66OTA contractor report, Casazza, Schultz & Associates, supra note 64, p. A-1.

2. the joint ownership of several large coal and nuclear power plants can complicate the reporting of a utility's share of a transaction; and
3. the existence of a tight power pool with central dispatch in the region may reduce the need for many intraregional bulk power sales among members.[67]

The goal of central dispatch in MAAC is to reduce costs by using the most economically efficient available generation to meet load. Coal plants are used to back out expensive oil generation. These transactions are conducted both within PJM Interconnection and with other regions, especially ECAR.[68] The NGA survey indicates that MAAC contracted to buy about 3,700 MW of power and to sell 1,300 MW.

Coordination

MAAC has one of the most highly integrated power pools in the country. PJM has strong internal interconnections, especially a strong west-to-east transmission system, which transfers power from minemouth plants in western Pennsylvania to load centers in the East, and interregional connections with ECAR, NPCC, and SERC.[69]

PJM operates under a formal agreement that provides for the coordination of planning and operation, reserve sharing, and rates. Coordination in MAAC is handled well and may be better than any other region in the country, according to FERC.[70]

Reliability

A number of factors may affect MAAC's future reliability. These include a higher than projected load growth, inadequate performance of load management programs, delays in generation additions, limited transmission import capability, and decreased availability of existing generators.

The most critical of these factors, according to NERC, is a higher than projected load growth. Peak load growth is forecast at 1.3 percent annually for the 1988-1997 period.

Capacity margins are forecast to range from about 19 percent in 1988 to 20.3 percent in 1997. MAAC expects these margins to provide sufficient generating capacity over the next decade, However, if load growth increases beyond projections, margins may be inadequate by the mid 1990s, even if all planned capacity is installed on schedule.

Another potential adverse impact on reliability involves increases in loading on MAAC'S transmission system. Heavy power flows can also increase loading on other utilities' systems not party to the transactions, as well as decrease reliability and limit economic benefits from internal energy transfers. NYPP's importation of hydropower from Canada has affected MAAC'S transmission system. To counteract this, the New York Power Pool (NPCC) and PJM have agreed on what constitutes normal and excessive use of each others' transmission system. The agreement includes an arrangement to purchase and install phase shifters in 1988. Phase shifters change the way power flow divides along different paths—decreasing flows that are too high and increasing those that can safely be increased. (See box 6-A on OTA's transmission case study-" Importing Power From Canada to New England.")

Still another potential source of adverse impact is disturbances caused by sudden loss of generation in regions outside MAAC. A loss of generating sources to the north and east of the MAAC region will cause a significant increase in power flows from the west to the east—ECAR to MAAC. This west-to-east power flow could adversely affect the reliability of the MAAC system. According to NERC, MAAC and neighboring regions participate in coordinated planning and operation to ensure that adequate reliability is maintained.

Because of its reliance on coal-fired power plants, MAAC maybe affected if stringent new pollution control requirements are adopted as part of acid rain legislation. Compliance could require that some older plant.. be retired and that output be reduced at other plants, If plant availability is reduced, regional reliability levels could be affected. The potential for power purchases by MAAC utilities from coal plants in ECAR could also be limited by constraints on capacity availability in that region.

Finally, in the late 1990s MAAC will increasingly depend on nonutility generation additions to offset capacity shortfalls. NERC has estimated that over the next 10 years about 2,860 MW of cogenerated power will be installed, bringing the total to 3,126 MW by 1997.

[67] DOE, supra note 58, p. 43.

[68] Ibid.

[69] FERC, supra note 57, p. 72.

[70] Ibid, p. 78.

Box 6-A—Transmission Case Study: Importing Power From Canada[1]

To meet rapidly growing load as well as displace expensive oil-fired generation, New England utilities are pursuing a variety of new supply options. One seemingly attractive option is to import power from neighboring Hydro-Quebec, a Canadian utility. Unexpected low load growth combined with excellent hydroelectric facilities give Hydro-Quebec a large surplus of low-cost power. However, the transmission systems of Quebec and New England are not synchronized and can only be linked by high-voltage direct current (HVDC) ties. At present, the Hydro-Quebec system is connected to the Eastern Interconnection through five HVDC ties with a capacity of 2,590 MW. A power purchase agreement called the Phase I Project was developed to make full use of the existing facilities.

Phase I Project

The Phase I Project consists of a formal agreement for the sale and transmission by Hydro-Quebec to NEPOOL of 33 million MWh of surplus hydroelectric power over an 1 l-year period, beginning in 1986. This energy purchase agreement does not guarantee that NEPOOL will obtain any specified amount of power at the time of its critical needs. However, NEPOOL does treat this agreement as reliable enough to justify not building 600 MW of capacity.[2]

At present, imports are constrained by 1) limited capacity of existing AC-DC converters at two locations-Des Cantons and Comerford; 2) limitations in the AC systems in New England; and 3) lack of agreement to transfer more power. An expansion of transmission facilities, called the Phase 11 Project, has been proposed to eliminate these bottlenecks.

Phase 11 Project

The Phase 11 proposal calls for a total additional firm energy purchase of 70 million MWh over a 10-year period, beginning in 1990, and for the building of necessary transmission facilities for its delivery. In general, NEPOOL will be entitled to schedule deliveries in any hour up to the 2,000 MW capacity of the tie. There are limitations on the rate of change of deliveries from one hour to the next, and Hydro-Quebec may interrupt deliveries during limited periods of time. NEPOOL considers the Phase 11 agreement a reliable source of 900 MW. Thus, the combined Phase I and II will replace 1,500 MW of additional installed capacity in New England.[3]

Transmission limitations will be resolved by adding both HVDC and AC components. In Canada, the HVDC components consist of a new 700-mile HVDC line and an AC-DC convertor rated at 2,000 MW. In the United States, the Comerford-Sandy Pond line will be extended by 133 miles. The NEPOOL AC system also has to be expanded to absorb the additional Phase II power and distribute it to various load centers in New England. The AC expansion consists of constructing two new 345 kV AC transmission lines, totaling **51.8** miles, along existing transmission rights-of-way. In addition, substantial substation reinforcements are required.

While these new facilities would allow increased transfers without overloading the New England and Hydro-Quebec systems, the project could create increased costs and transmission constraints in neighboring regions. These effects underline the importance of considering the impacts of one region's changes on other regions.

Interregional Impacts

Increased imports as well as reliability concerns have an impact on the operation of other regional systems. Because NEPOOL, NYPP, PJM, ECAR, and other systems that make up the Eastern Interconnection are all interconnected and operate synchronously, serious disturbances could be propagated from one of the systems to its neighbors and even to more distant systems, This is particularly important given the large size of the Canadian transfers. The loss of the Phase 11 transmission system would result in a disturbance much worse than the loss of the largest generator in the Northeast.

When the power supply in New England is suddenly reduced by 2,000 MW, the maximum that can be lost due to any contingency, this loss is immediately replaced by power generated in New England and in all the areas connected with New England, from the Rocky Mountains and the Gulf Coast to Nova Scotia. Most of this power is generated in areas to the west of New York and PJM, and passes through these on the way to New England.

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1 This material is drawn from an OTA contractor report, Casazza, Schultz & Associates, Inc., "Case Studies of Transmission Bottlenecks," Nov. 30, 1968.

2 "New England/Hydro Quebec 405 kV Transmission Line Interconnection—Phase II," Final Envi ronmental Impact Statement, Economic Regulatory Administration, Office of Fuel programs, DOE, August 1987.

3 New England Hydro-Transmission Electric Co., "Amendment to Supplement 2C to Long-Range Forecast 2 for the Ten-Year Period 1%4- 1993, " submitted to the Massachusetts Energy Facilities Siting Council, November 1984, vol. 1, p. 4.

These large power flows are added to the predominantly eastward economic power flows in the PJM and NYPP areas from ECAR and other midwestern areas. The very large combination of the eastward power flows through PJM and NYPP can cause thermal overloads, inadequate voltages, and possible instability on heavily loaded circuits.

The MEN Study Committee, a group representing PJM, ECAR, and NPCC, found that Phase 11 imports of less than 1,500 MW do not require PJM or NYPP to restrict their power transfers more severely than they must for contingencies in their own system. Larger imports, up to 2,000 MW, would affect PJM restrictions but not those of NYPP, according to the MEN Study. PJM would have to restrict its imports from ECAR more severely—to **3,250** MW or less—than if it were responding to a contingency in its own system, or risk severe voltage problems if NEPOOL lost its Phase 11 imports. Therefore, Phase II imports may not be increased to 2,000 MW unless PJM is importing 3,250 MW or less from ECAR.

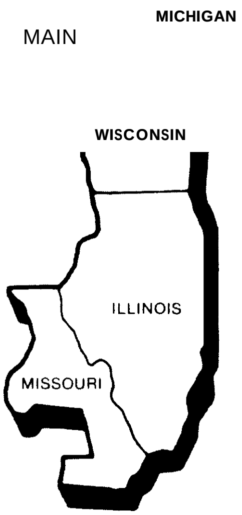
An alternative to restricting imports would be to install additional transmission facilities on either the PJM or NYPP systems. Technical details and costs of such changes have not been determined, and the allocation of any costs would have to be negotiated among the parties involved.

Economic (consequences

Some consideration has been given to what transmission reinforcements would be necessary to remove existing limitations on the ECAR-to-PJM and NYPP transfers. The exact nature of these reinforcements, their cost, and the amount by which these limitations would be relieved are not available because studies have been, for the most part, informal and preliminary. The informal general consensus among system planners in the region seems to be that the cost of increasing transfer capabilities by substantial amounts is likely to exceed the economic gain produced by these increases, at the present cost differentials.

The Phase II power imports agreement is estimated to produce capacity and energy cost benefits with a present worth of $1,849 million at an estimated cost of $948 million. These benefits will be reduced somewhat by the need to limit the total imports to less than full capacity of the HVDC ties, whenever increasing imports would threaten the reliability of systems in New York or Mid-Atlantic areas.

Mid-American Interconnected Network (MAIN)



Voting membership is open to al I but one of the original signers of the MAIN agreement and to any other power supplier that has a 115 kV or higher interconnection with a regular mem - ber, whose operations have a significant impact upon reliability, and who undertakes the obligations of the MAIN Agree ment.[71]

Fuel Use

MAIN relies heavily on coal and nuclear power to generate electricity. By 1997, NERC predicts coal's share will increase slightly and nuclear's share will decline.

Capacity

NERC anticipates installed capacity to decline slightly over the next 10 years. The recent addition of **4,310** MW should be adequate to maintain reliability through 1997. No major additional units are planned during the 1988-1997 period.

Annual summer and winter peak demand are projected **to** increase 1.6 and 1.9 percent respectively during this period.

Transmission

NERC indicates that the region's transmission system is adequate for reliable operation of both internal and interregional transfers. Interconnections to the east and southeast provide substantial capability for interregional transfers from MAIN to other regions. Several new lines are scheduled for service within the next few years.

To assure adequacy, MAIN conducts studies on a regular basis. Also, MAIN participates in two interregional reliability coordination agreements. One ineludes MAIN, ECAR, and the Tennessee Valley Author-

[71] '' Reliability Council Survey Responses, " supra note 2, p. 7

ity (TVA) subregion of SERC. The other includes MAIN, MAPP, and SPP.

Bulk Power Transactions

According to DOE, MAIN has a low volume of reported transactions. One reason may be that the largest utility in the region-Commonwealth Edison—uses most of its coal and nuclear capacity in its own heavily loaded service territory. Also, the lack of established transmission access agreements may limit large-scale purchases and sales.[72]

Those utilities that have abundant coal capacity sell to or interchange power with those that are dependent on oil and gas or need additional capacity to meet load.[73] The NGA survey respondents contracted to buy only 213 MW and to sell 585 MW.

Coordination

Individual bilateral agreements appear to form the core of coordination within this region. For example, coordination between MAIN and MAPP is established through a bilateral agreement. Interregional coordination with several other contiguous regions is pursued through bilateral agreements. FERC has indicated that expansion of a power pool or coordinating group within the region, rather than dependence on individual bilateral agreements, could improve coordination which in turn could improve bulk power supply economy .74

Reliability

A couple of factors may affect the region's reliability in the future. They are acid rain regulations and a higher than projected peak demand. Because coal is the predominant boiler fuel in the region, new regulations to further reduce sulfur dioxide and nitrogen oxides emissions may affect generation. Older units may have to be retired while others would be retrofitted with emissions control equip ment. The cost and lead times to retrofit and/or replace capacity could prove significant and may affect reliability by cutting plant availability.

NERC projects a capacity margin of 15.2 percent for 1997. if loads grow faster than anticipated, additional capacity will be required by the mid 1990s. According to NERC, MAIN utilities may encounter difficulties in adding new generation and capacity in a timely manner.

Mid-Continent Area Power Pool (MAPPJJ.S.)

MAPP-U.S.

MAPP operates as a formal power pool. Its voting members are electric utilities that own/lease and operate one or more generating units to meet all or part of the system load; are directly interconnected with one or more participants in order to meet obligations of the MAPP Agreement; operate or participate in a 24-hour dispatch center with a terminal on the MAPP communication network; and maintain Accredited Capability[75] during each month.[76]

Fuel Use

MAPP relies heavily on coal and nuclear power for electricity generation. Coal use, which now accounts for little more than two-thirds of electricity generated, is expected to increase to 70.8 percent by 1997. Nuclear's share is expected to decline to 17.5 percent, and hydro's share will decline slightly.

Capacity

Between 1988 and 1997 installed capacity is projected to increase by only 740 MW. This increase consists primarily of a 400 MW coal-tired unit and the return of retired units to service,

Summer peak demand is expected to grow by 1.5 percent annually and winter peak by 1.6 percent annually for the forecast period. MAPP utilities are actively pursuing various load management programs to reduce growth in peak demands.

Transmission

MAAP has experienced increased internal and interregional use of its transmission systems for economy and emergency energy transfers, For example, NERC reported that in 1986 transfer capacity between MAPP-U.S. and MAPP-Canada was utilized at 71 percent of maximum capacity; interregional energy transfer capacity between MAPP and WSCC was almost 87 percent.

72DOE, supra note 58, p. 43.

73Ibid.

74FERC, supra note 57, p. 109.

75Net generating Capability plus purchased power excluding economy energy, minus commitments.

76"Reliability Council Survey Responses," supra note 2, p. 8.

Furthermore, interregional transfers from MAPP to MAIN and SPP have been increasing annually since 1976 and are expected to continue over the next decade. According to NERC, improvements currently underway or planned should help alleviate concerns. NERC expects the region's transmission facilities to be adequate through 1997.

Bulk Power Transactions

MAPP utilities take advantage of their significant coal-fired capacity by selling to utilities in other regions. Bulk power transactions within the region are based on least-cost generation, But. the region's lack of generation diversity may limit the potential for large-scale purchases and sales.[77] The NGA survey indicated that MAPP respondents contracted to sell 1,900 MW and to purchase 2,470 MW.

Coordination

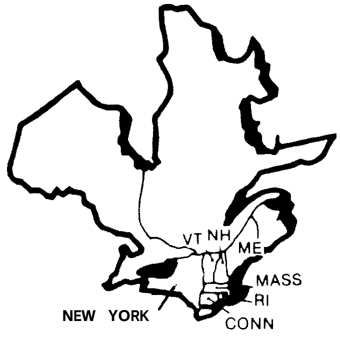
MAPP consists of the Upper Mississippi Valley Power Pool, the Iowa Power Pool, and the Nebraska Public Power Systems. Pool agreement provisions cover capacity and transmission plans and requirements and daily and seasonal operations. However, the pool agreement does not oblige members to provide bulk power supplies to other members over a long period of time. Individual utilities would have to independently arrange for their power needs.[78]

Reliability

Capacity margins for summer peak periods in MAPP are projected to decrease from 27.6 percent in 1988 to 21.4 percent in 1997. Although capacity margins will decrease during this period, NERC expects that they will meet reliability criteria and should therefore be adequate.

Some of MAPP's coal-fired generation could be affected by additional pollution equipment requirements to control acid rain precursors. The available power from these units could be reduced, which in turn, would have a negative impact on the region's reliability. But, the impacts in this region are expected to be much less than in ECAR and .MAIN.

Northeast Power Coordinating Council (NPCC)



NPCCU.S.

NPCC includes members in the United States and canada. Member systems in New England form the New England Power Pool (NEPOOL), and member systems in New York form the New York Power Pool (NYPP). Memberships available to electric systems which have a substantial effect on the service reliability of the Northeast interconnection.[79] The discussion in this section refers to the U.S. portion of NPCC unless otherwise noted.

Fuel Use

NPCC member utilities rely most heavily on nuclear and oil, followed by coal and hydro to produce electricity. NERC projections for 1997 show that nuclear's share is expected to increase; oil and coal use will decrease.

Capacity

NPCC installed capacity is projected to grow at an annual rate of 1.2 percent from 1988 to 1997. During this same period, annual summer and winter peak demand are expected to grow at 1.9 percent and 1.3 percent respectively. NERC projects that about 6,000 NIW of new capacity will be added by 1997. The only major utility-owned capacity addition scheduled for service in New England over the next decade is the Seabrook I nuclear plant. The Ocean States Power Project, an independent power project which is owned jointly by several utilities and a Canadian gas pipeline company, also is expected to contribute 470 MW of capacity.

Transmission

NPCC transmission systems have experienced dramatic increases in power flows over the last 10 years. The increases have been due to fuel price differentials, the need to locate generating resources farther from urban load centers, and the growing reliance of NPCC systems on generating resources in Quebec. NERC expects heavy flows to continue in the future. Construction of several new transmission lines from HydroQuebec and upstate New York to load centers in southeastern New York and New England will provide additional sources of genera-

[77]DOE, supra note 58, p. 44.

[78]FERC, supra note 57, p. 110.

[79]'Reliability Council Survey Responses," supra note 2, p. 9.

tion and improve reliability. These imports will require the continued use of special protection and control systems to maintain transmission reliability in NPCC and adjacent regions.

Bulk Power Transactions

According to DOE, most of the bulk power transactions in this region are based on reducing costs at the margin by taking advantage of load diversity and operating differences. The biggest purchasers of electricity, according to DOE, are the utilities that have coal-fired capacity. These utilities also tend to be the largest utilities with the heaviest loads.[80]

Determining NPCC's volume of bulk power transactions is difficult for a couple of reasons. One reason is the different methods of reporting within NPCC. (NYPP utilities report their pool transactions as purchases and sales, while NEPOOL reports their transactions as interchanges.) Another reason is that joint ownership of power plants in the region tends to complicate reporting of purchases and sales.[81]

The NGA survey indicated that NPCC utility respondents engaged in a relatively low volume of bulk power transactions, compared to other regions. Utility respondents contracted to sell about 1,091 MW of power and to buy 2,356 MW. Like MAAC, the existence of the two tight pools in NPCC may obviate the need for a lot of intraregional transactions among members.

Coordination

NEPOOL and NYPP are two of the most integrated power pools in the country. Both have strong interconnections that provide for substantial interpool and interregional transfer capability including imports from Canada.[82]

Both pools operate under formal agreements that provide for joint organization, planning, and operation. Because NEPOOL's membership is more diverse, its agreement is more complex and comprehensive than NYPP's.[83] In addition to the pool agreements, the utilities are tied together through dozens of bilateral agreements.

Reliability

According to NERC, supply adequacy will depend on the installation of both utility and nonutility generation, the success of demand management and life extension programs, and large-scale power transfers. In NPCC, supply adequacy is also very dependent on demand not exceeding projected growth rates for the 1988-1997 period.

NERC indicates that projected capacity resources in New York are adequate to meet forecast demand through the next 10 years. This projection assumes that generation additions, including the Shoreham nuclear unit, are realized and demand management and life extension programs are successful. For NEPOOL, NERC estimates capacity should be adequate through 1992/1993. Beginning in 1993, NEPOOL's resources are expected to fall below NPCC's reliability criteria. NERC's current projection for this region differs from that reported in its 1987 reliability assessment, which expected capacity resources to be adequate through 1996.

Oil-fired units represent about half of total New York and New England generating capacity. This heavy dependence on oil and the future availability of adequate oil supplies are major reliability concerns to NPCC utilities. The availability of the region's nuclear capacity is also important. Boston Edison's Pilgrim nuclear unit has been shut down by the Nuclear Regulatory Commission (NRC) because of safety considerations. The NRC has given approval to restart the unit but the Commonwealth of Massachusetts is opposing that decision based on its concerns over the feasibility of developing adequate emergency evacuation procedures.

Southeastern Electric Reliability Council (SERC)

Voting membership in SERC is open to any power supply entity operating or responsible for operating facilities connected to the interconnected power system, which is located in the SERC membership area and which provides bulk power supply with a normally connected generating capacity of 25 MW or more. Non-voting membership is open to four representatives on a sub-regional basis for each of two categories: 1) municipal or other

[80] DOE, supra notc 58, p. 44.

El Ibid, p. 45.

[82] FERC, supra note 57, p. 73.

[83] Ibid, p. 74.

publicly-owned systems: and 2) rural electric cooperatives.[84]

Fuel Use

SERC members rely on coal and nuclear power, and to a much lesser extent on hydropower, to produce electricity. In 1988, NERC expects coal to account for almost 60 percent of electric power production, and nuclear about one-fourth. By 1997, NERC projects that coal's share will decrease slightly and nuclear will increase.

Capacity

The SERC region will experience the largest growth in installed capacity. NERC expects that about 17,236 MW of new capacity will be added between 1988 and 1997. In addition, about 6,200 MW of nonutility generation are projected for this period. Based on these projections, the annual growth rate will be 1.8 percent through 1997. At the same time, both winter and summer peak demand growth are projected to increase by 2.4 percent annually.

Transmission

The existing SERC transmission system includes about 27,000 miles of 230 kV+ powerlines. SERC is interconnected with transmission systems in four other regions: SPP, MAIN, ECAR, and MAAC. During the 1988 to 1997 period, over 600 miles of 500 kV and 1,700 miles of 230 kV lines are expected to be added. Included in SERC's plans are two major 500 kV interconnections between SERC and SPP and one major 500 kV transmission interconnection between SERC and ECAR.

NERC expects that existing and planned facilities will provide adequate energy transfer capability between SERC and other regions, and among SERC subregions. Certain portions of the system, however, are experiencing and will continue to experience heavy use, Because of this, several key tie lines between utilities, subregions, and regions are closely monitored. These include the TVA- MAIN Interface near Paducah, Kentucky; Southern-VACAR Interface near the Savannah River; TVA-SPP Interface near Memphis, Tennessee; and the Southern Co.-Florida Interface.

Bulk Power Transactions

SERC has abundant and diverse generating capacity. The availability of coal-fired and hydro capacity, especially in the Southern Company service area, and the Carolinas, affects the volume and type of bulk power transaction within the region. Transactions are also influenced by the amount of oil capacity in Florida and Virginia. For example, Florida and Virginia utilities buy coal-generated electricity from Southern utilities to back out oil capacity. Most of these transactions are used to obtain marginal co~t reductions by exploiting load diversity.[85]

Also, there are substantial transactions between SERC and ECAR that involve the sale of coal-generated power to utilities that depend on oil capacity .X6 According to the NGA survey, SERC accounted for the largest volume of bulk power tranwtions in both sales and purchases. SERC has contracts to buy more than 12,750 NIW. Sales contracts total over 7,480 MW.

Coordination

SERC is divided into four subregions: TVA, Southern, VACAR, and Florida. Strong interconnections exist in a north-south direction between TVA and Southern Companies and in an eust-west direction between Southern and VACAR. Interconnections between TVA and VACAR are limited.[87]

Coordination among the four subregions is achieved primarily through bilateral agreements. Southern Co. affiliates are tied together in the holding company pool. The Florida utilities participate in an energy broker system, which provides some of the benefits of a formal pool arrangement. VACAR and I"VA use bilateral interchange agreements to coordinate bulk power transactions.[88]

Reliability

NERC expects that generating capacity margins in this region should be adequate during [he 1988-1997 period, provided capacity additions and peak demand are as projected. NERC also expects that SERC transmission systems will provide adequate emergency transfer capacity between SERC and other regions and among subregions.

~~' 'Re] iabi]ity Council survey Responses, " Wpra nOIC ~, p. 9.

xfDOE, Supra note 58, p. 45.

[86]Ibid.

[87]FERC, supra notc 57, p. 83.

[88]Ibid, p. 85.

Southwest Power Pool (SPP)

Voting membership in SPP is open to any system that: is interconnected at 115 kV or above with any SPP member; owns and controls a 115kVorhighertransmission line in synchronous operation and with an installed total capability of 100 MW or greater; owns or controls not less than 300 MW of installed generating capacity with the SPP area; makes a significant contribution to overall reliability in SPP; generates on a 24-hour basis; and has a 24-hour dispatch center or has contractual arrangements with a load control area to fulfill that function. Nonvoting membership is open to utilities which serve 25 MW of load and control not less than 25 MW of operable generation in synchronous operation of a transmission interconnection with an SPP member.[89]

Fuel Use

SPP members rely heavily on coal and to a lesser extent on gas and nuclear power to produce electricity. Over the 1988-1997 period, the fuel mix will remain fairly constant.

Capacity

Between 1988 and 1997, NERC expects that installed capacity will increase slightly by 2,538 MW, which translates into an annual growth rate of 0.4 percent. Summer peak demand is expected to grow 1.9 percent annually, and winter peak demand to grow 2.2 percent annually.

Transmission

The SPP region has an extensive transmission network that includes three direct interconnections from SPP to other regions. In the next decade, SPP plans to install about 1,500 miles of transmission lines, 230 kV and above. Also, two additional interregional circuits are planned to include an interconnection with SERC (TVA) and another dc interconnection with ERCOT

Interties to the east and northeast provide substantial interregional transfer capability between SPP and SERC and between SPP and MAIN. Interregional transfer capability also exists between SPP and MAPP, but on a smaller scale. Interconnections between SPP and ERCOT are limited because the Texas system is not synchronized with the Eastern system. Similarly, the lack of ties between SPP and the Western United States precludes significant direct emergency power transfer,[90]

According to NERC, SPP's transmission system and interconnections with other regions are adequate and no lines present significant bottlenecks to economy or emergency energy transfers for the 1988-1997 period.

Bulk Power Transfers

Each of SPP'S three distinct regional groups—Middle South Group, the Missouri-Kansas Power Pool (MOKAN), and the Oklahoma Group--relies on a different generating capacity mix. Because of these differences in generating capacity, each group engages in different types of bulk power transactions. For example, Middle South engages in substantial purchases and sales and to a lesser extent interchange; MOKAN emphasizes interchange transactions; and the Oklahoma group has more sales than interchanges.[91]

Generally, the utilities that depend on natural gas generation use bulk power transactions to reduce marginal costs, while utilities with coal-fired capacity are either using the transfers to meet native loads or selling coal-generated power to other utilities with oil and gas capacity.[92]

Coordination

Planning and operating coordination is accomplished primarily through the three regional groups. Multiparty pooling, coordination agreements, and bilateral agreements form the core of coordination within SPP.[93]

Middle South Utilities (MSU) is fully interconnected and coordinated. It operates under a formal agreement to which all operating companies and the service company are signatories. MOKAN members individually dispatch their own generating resources. While MOKAN does not practice central dispatch, the systems have arrangements for the economy energy exchanges. Many MOKAN members participate in one or more joint agreements to build transmission facilities in the area.[94]

89 'Reliability Council Survey Responses," supra note 2, pp. 9-10.

90 FERC, supra note S7, p. 121.

91 DOE, supra note 58, p. 47.

92 Ibid.

93 FERC, supra note 57, p.119.

94 Ibid, p. 124.

Reliability

SPP anticipates adequate generating capacity margins during the forecast period. The primary reliability concern, according to NERC, is transmission access.

Western Systems Coordinating Council (WSCC)

Membership in WSCC is open to any electric utility or group of utilities in the region regardless of the type of facilities or system size. Voting membership is available to entities with generation in excess of 100 MW or transmission above 230 kV. The Council consists of one representative per member system.[95]

Fuel Use

WSCC members are divided into four separate subregions: the 'Northwest Power Pool, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, and the California-Southern Nevada Power Area. Fuel use in each of these subregions is very different, For example, the utilities in the Northwest Power Pool, which is winter peaking, rely primarily on hydropower; the Rocky Mountain Power Area, which is either winter or summer peaking, relies on coal and hydro; the Arizona-New Mexico Power Area, which is summer peaking, relies on coal- and gas/oil- fired generation; and the California-Southem Nevada Power Area, which is summer peaking, is heavily dependent on gas- and oil-fired generation.

Capacity

Net generation additions of 16,771 MW are projected by 1997. The projected additions are considerably less that the net additions placed in service during the past 10 years, however. This reduction is in response to recent lower load growth projections and to the availability and abundance of capacity resources in WSCC.

The annual growth for 1988-1997 is 1.0 percent. During the same period, summer peak demand is expected to grow 1.9 percent annually, and winter peak, 1.7 percent annually.

Transmission

WSCC's overall bulk power transmission network links the principal population centers with major north-south lines along the Pacific Coast and through the intermountain plateau. East-West lines tie the system together. The result is an irregular large loop configuration, often called the "doughnut," rather than an interlocking system that is found in the East. Few transmission lines cross the sparsely populated 'hole" of the doughnut in Nevada.

According to NERC, WSCC transmission systems are adequate to accommodate anticipated firm and most economy energy transfer schedules during the 1988-1997 period. Of continuing concern is the effect of heavy economy transfers on bulk electric power system reliability. Because of the region's load diversity and capacity resource mix, plus surpluses of base-load capacity and large fuel price differentials, economy energy transfers between areas are likely to continue.

WSCC members are currently making improvements in the system in order to maintain an acceptable level of reliability. These include upgrading and increasing transfer capability, and completion of additional lines. During 1987, a portion of the new AC Pacific Intertie was placed in service to improve reliability. And, several utilities are planning to install phase shifters on lines connecting Utah/Colorado and Arizona/New Mexico. The phase shifters are scheduled for operation during 1989-1991 and are expected to mitigate the Regions loop-flow problems.

Bulk Power Transactions

There is a heavy volume of bulk power transfers in the WSCC region. Utilities with coal-tired capacity in Utah, Wyoming, Arizona, and New Mexico sell power to California to back out oil and gas. Coal-fired electric power is also sold to the Northwest to supplement hydropower during dry spells and during winter peak periods. The Pacific Northwest sells hydropower to California utilities and other Southwestern States when water conditions permit and during summer peak periods.[96]

Coordination

Coordination and pooling have evolved on a subregional basis among utilities with similar needs and problems. No pool formally plans bulk power facilities as

[95] "Reliability Council Survey Responses, " supra note 2, p. 10.

[96] DOE, supra note 58, p. 47.

a single integrated system to serve the combined load growth of its members.[97]

The Arizona-New Mexico Power Area participates in a number of coordination arrangements, which in many cases relate to specific projects and conditions. The Rocky Mountain Power Area and the California-Southern Nevada Power Area rely on bilateral coordination arrangements. And, the Northwest Power Area utilities adhere to the Pacific Northwest Coordination Agreement, which provides for the coordination of resources and establishes rights, obligations, and procedures for all signatories.[98]

According to FERC, power pooling could be especially effective in the Rocky Mountain and Arizona-New Mexico power areas. In the Northwest Power Area, substantial bulk power supply economies are being realized from the coordinated planning efforts of the area's utilities brought about by passage of the Northwest Power Planning Act of 1980.[99]

Reliability

NERC projects that generating capacity margins will range from 33 percent to 26 percent over the next 10 years and will adequately meet demand.

Alaska

Fuel Use

Fuel use varies by region within Alaska. For example, the Rail belt region (Anchorage-Fairbanks) relies primarily on indigenous natural gas to generate electricity; southeastern Alaska is served primarily by Federal and State hydropower projects; and the widely dispersed villages in the rest of the State obtain electricity from diesel-fueled generators, ranging from 50 KW to 7 MW.[100]

Capacity

Alaska's 1986 installed generating capacity was 2,433 MW, an increase of 5.6 percent over 1985 figures. About two-thirds of the installed capacity was in the utility sector; 25 percent in the industrial sector; and about 6 percent in the military sector. According to the Alaska Power Authority, the military's share may continue to decrease if military facilities continue to contract out power production responsibilities to the private sector.[101]

Because of the State's economic recession, current projections are negative for the short term and around 2 to 3 percent over the next 10 to 15 years. The Railbelt region has the largest concentrated segment of load in the State. In the southeast, three major communities use substantial amounts of power: Juneau (55 MW), Sitka (22 MW), and Kethikan (20 .MW). The largest rural towns have loads in the 4- to 5-MW range. Load growth forecasts are low for most areas of the State.[102]

Transmission

Alaska has few interconnected electric utilities. The Railbelt region has the strongest interconnected system in the State while all southeast communities are isolated and lack major interties.

Alaska's transmission network consists of 1,681.5 circuit miles. Almost 80 percent of the network is in the Fairbanks and Anchorage-Cook Inlet areas.[103]

Reliability

Reliability continues to be a major concern in Alaska. In the Railbelt, for example, reserve margins are required to be 30 percent. In the rural areas, communities are essentially on their own for electricity, and utilities typically provide high reserve generation levels. Reserve margins of 100 percent are prudent. According to the Alaska Public Utilities Commission, reliability should improve for many isolated systems over the next 20 to 50 years as many communities become interconnected. 'w

97FERC, supra note 57, p. 137.

98Ibid.

99Ibid.

100Alaska Public Utilities Commission letter to OTA, dated Aug. 30, 1988.

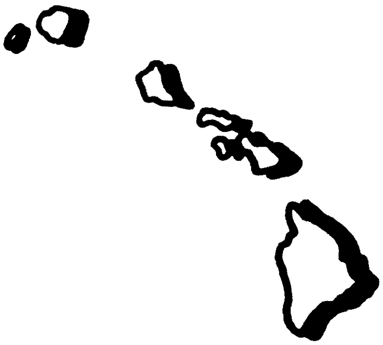
101Alaska power Authority, *Alaska Electric Power Statistics 1960-1986*, November 1987, p. 1.

102Alaska Public Utilities Commission letter, supra note 100.

103Alaska Power Authority, supra note 101, p. 61.

104Alaska Public Utilities Commission letter, supra note 100.

Hawaii



The Hawaiian Electric Company (HECO) provides electricity to Oahu and to three other Hawaiian Islands through its subsidiaries Hawaii Electric Light Company (HELCO) and Maui Electric Company (MECO). The systems cover about 95 percent of the Islands.

Fuel Use

Hawaii is heavily dependent on oil and will continue its reliance well into the future. In 1986, oil-fired capacity provided about 93 percent of total capacity. The remainder is supplemented by purchased cogenerated electricity from sugar processing facilities and from wind power companies. In Maui, cogeneration from sugar processing facilities contributes about 19 percent of the island's electricity requirements.[105] However, power contributions from sugar processors or from other renewable resources are not expected to increase substantially.

Capacity

Hawaii's installed capacity in 1986 was 1,535 MW. HECO reports peak demand is 1,205 MW.[106] System peaks occur in the evening. However, HECO projects that by 1990 peaking will occur during the day.

Transmission

The electric systems on each island are not connected with each other. The lack of transmission capability is the biggest impediment to development of the Islands' indigenous resources. For example, the geothermal reserves on the Big Island are considered extensive enough to fulfill most of the State's power needs, but are located far from the load center in Oahu.

Hawaii has 1,465 miles of transmission lines. Hawaii Light Company, an affiliate of HECO, has begun construction of two lines totalling 50 miles. The cost was estimated to be about $11 million.[107]

Reliability

HECO reports a reserve margin of 22 percent for 1987 and projects an increase to 35 percent by 1990.

[105] Public Utilities Reports, Inc., *The P.U.R. Analysis of Investor-Owned Electric and Gas Utilities*, 1987 edition, August 1987, pp. 148-149.

[106] Ibid.

[107] Ibid.