Chapter 7

Regional Differences Affecting Technology Choices for the 1990s

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Chapter 7

Regional Differences Affecting Technology Choices for the 1990s

INTRODUCTION

Overview

The inherent uncertainty associated with estimating future electricity demand is one of the most important factors affecting utility choices among electricity supply options. Demand growth rates differ dramatically within and among regions, and unanticipated changes in these rates can substantially affect both overall system reliability and the need for new generating capacity. Other factors that vary by region also strongly influence utility technology choices. This chapter focuses on these differences, quantifies them where possible, and speculates on their short- and long-term influence.

Among these other differences are plant life extension opportunities (defined by the age and type of existing generating facilities) and present and projected fuel dependence, which generally establishes regional benchmarks for technology cost comparisons. Other variables discussed in this chapter include opportunities for increased power transfers; potential supply contributions from load management, conservation, and cogeneration; constraints imposed by natural resource availability; and differences in regional regulatory and economic environments.

Definition of Regions

While regions can be defined by many characteristics—e. .g., demographics, economic make-up, census divisions, and/or physical geography—the regions used most often in this chapter will be those of the electric reliability councils. There are nine regional councils in the United States and one national group: the North American Electric reliability Council (N ERC). Figure 7- l summarizes what the councils do and shows which areas of the country they cover. Figure 7-2 illustrates how these regions compare with census divisions, because occasionally data will be presented in this format as well.

REGIONAL ISSUES DEFINED BY ELECTRICITY DEMAND

The Role of Uncertainty in Regional Demand Forecasts

As noted in chapter 3, the national average annual rate of growth in electricity demand fluctuated greatly through the 1970s. Growth rate predictions have similarly varied. For example, in 1975, NERC expected demand growth to stabilize at 6.9 percent per year through 1984; as of early 1984, the council expected growth through 1993 to average 2.5 percent,[1] Other estimates range between 1 and 5 percent (see figure 3-4 in chapter 3). As figure 7-3 illustrates, small changes in expected growth lead to substantial differences in capacity requirements to meet overall demand.

Wide regional variations in demand growth rates have been and continue to be common. NERC 1984 projections for average annual demand growth in the next decade range from 1.3 (MAAC) to 4.0 percent (ERCOT). Comparable disparities also occur within regions. For example, within WSCC, which is divided into four subregions, the California-Southern Nevada Power Area expects demand growth of 1.9 percent,

[1]North American Electric Reliability Council (N ERC), *14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America* (Princeton, NJ: NERC, 1984).

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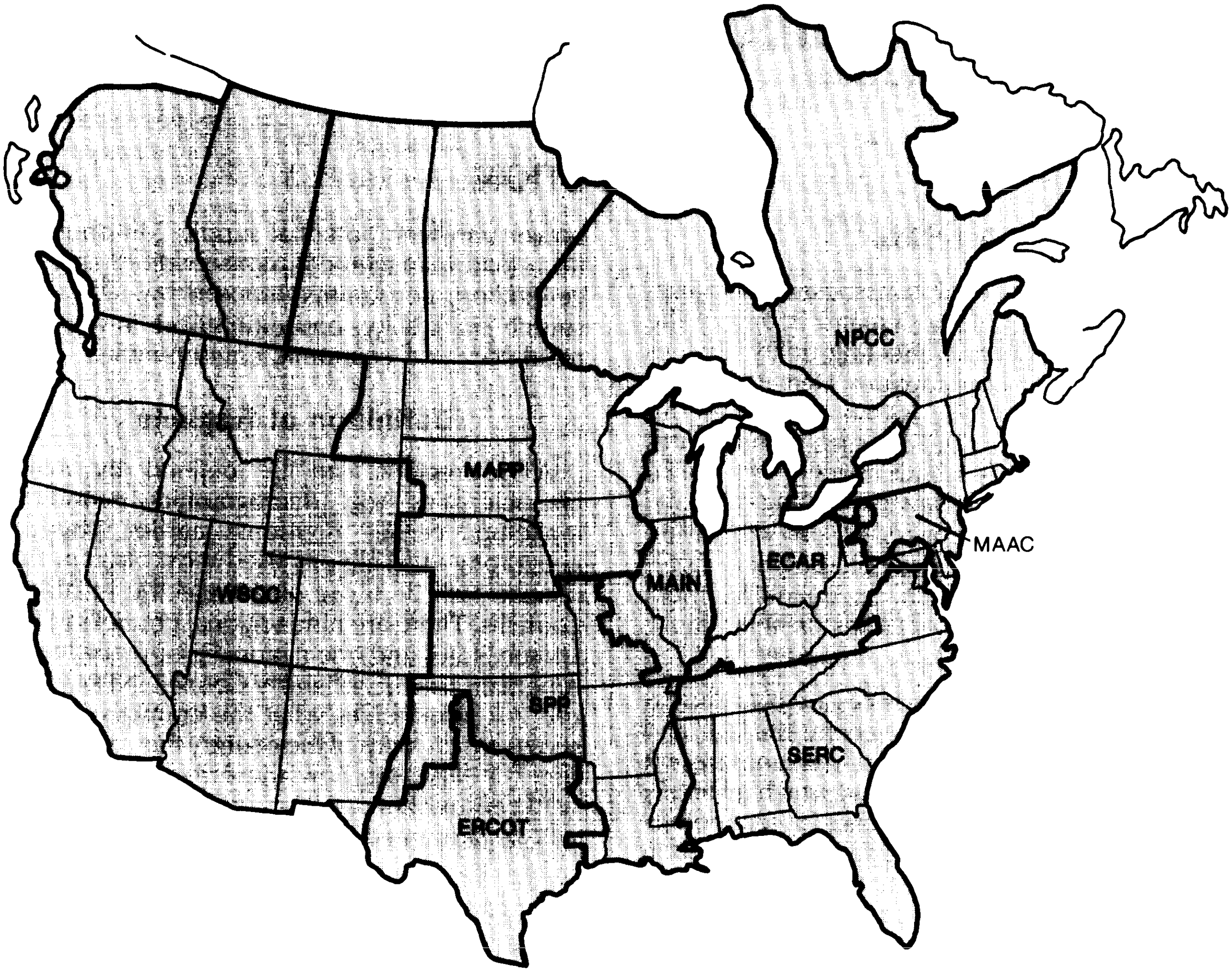
Figure 7-1 .—Map of North American Electric Reliability Council (NERC) Regions

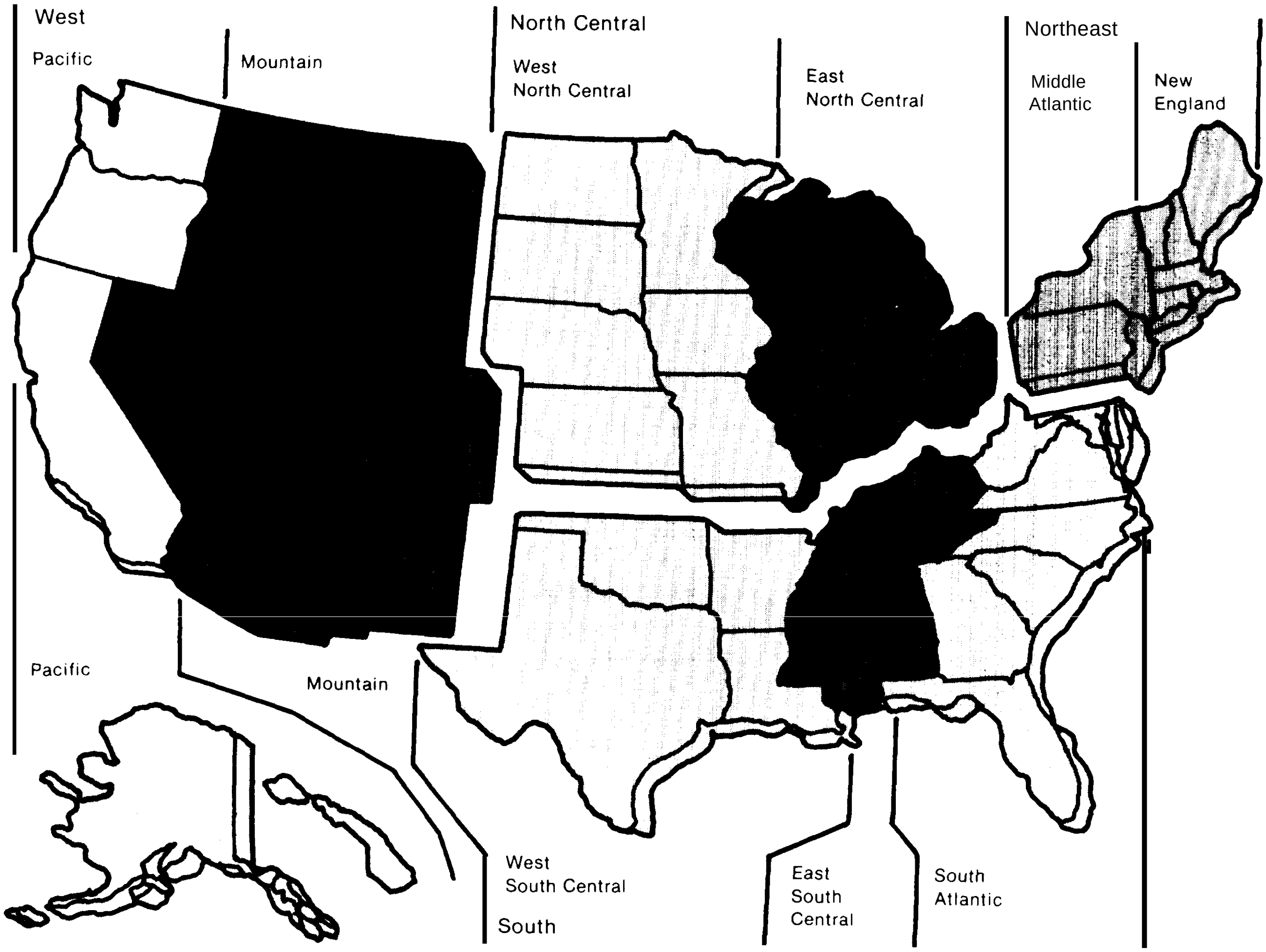


NERC helps ensure the adequacy and reliability of the U.S./Canadian electricity power supply system by acting as a forum for greater coordination between regional utility systems. The nine regional organizations listed below provide similar services to their member utilltles, Several of the regional councils have member systems in Canada. Throughout this chapter, statistics will be cited for U.S. members only,

ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interpool 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 (NERC), *NERC at a Glance* (Princeton, NJ: NERC, 1984)

Figure 7-2.—Map of U.S. Census Regions



SOURCE U S Bureau of the Census

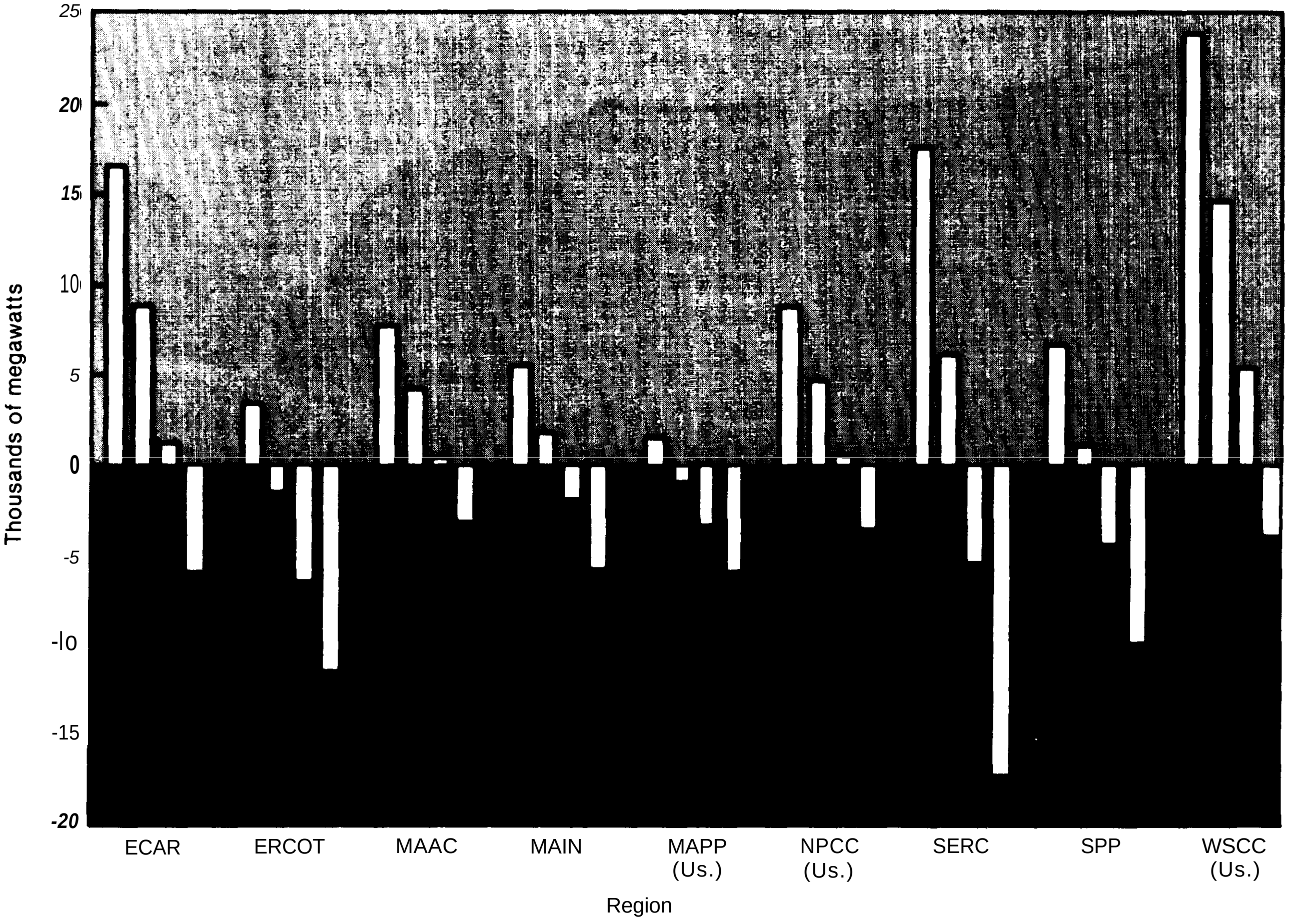
while the Arizona-New Mexico Power Area expects growth on the order of 4.4 percent.[2] Many factors underlie these differences in growth rates, including observed and expected consumer response to electricity prices and the prices of competing energy sources; regional and national economic structure and trends; the anticipated effects of cogeneration, load management, and conservation; varied utility system efficiency improvements; and new uses for electricity.

Historically, reserve mat-gins have been used as general indices of system reliability. As explained in box 7A, the definition of what constitutes an adequate reserve varies. While the traditional target has been 20 percent, utility systems within the same region may adopt different standards depending on many factors, including individual plant characteristics, access to power from other systems, and characteristics of customer demand. Looking at reserve margins on a regional scale thus suggests rather than defines the reliability issues in a given region.

As figure 7-3 suggests, reserve margin estimates are particularly sensitive to demand growth predictions. U.S. Department of Energy (DOE) projections based on current NERC demand *and capacity* forecasts indicate that, between 1984 and 1993, six of the nine NERC regions will at some point fall short of selected reliability criteria (see table 7-4). If future demand growth proves higher

[2] Ibid.

Figure 7-3.—1993 Regional Capacity Shortfalls or Surplus Relative to 20 Percent Reserve Margin Given Varying N;tional Demand Growth Rates and Current Utility Capacity Projections



In the figure above, regional demand is calculated under four different national demand growth rates: 1.5, 2.5, 3.5, and 4.50/o. The regional growth rates expected by NERC councils under the 1984 2,!5°/. forecast for national demand were used to establish relative weights for each region. These weights were then applied to the three other scenarios so regional differences in growth rates would be accounted for.

The 20 percent reserve margin for 1993 was calculated with the following formula:

$$\frac{\text{capacity planned for 1993} - \text{expected peak} \times 100}{\text{expected peak}}$$

These capacity projections do not account for contributions from power interchanges, nor are they adjusted for expected maintenance, outages, and similar factors.

Shortfalls and/or excesses were calculated as follows:

1993 planned capacity – (projected 1993 peak + 20 percent reserve margin)

SOURCE: Office of Technology Assessment, based on data presented in North American Electric Reliability Council (NERC), *14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America* (Princeton, NJ: NERC, 1984).

Box 7A.—Measures of System Reliability: Reserve Margins, Adjusted Reserves, and Capacity Margins

Reserve margins express the difference between demonstrated capacity and peak demand as a percent of total peak.[1] The definition of what constitutes an adequate reserve varies. For example, the Congressional Research Service[2] cites 15 percent as the lowest acceptable level and 20 percent as the optimum; the U.S. Department of Energy (DOE) sets an approximate criterion of 25 percent.[3] While the traditional target has been 20 percent, utility systems within the same region may adopt different standards depending on many factors, including individual plant characteristics (e.g., age, size, type), access to power from other systems, and characteristics of customer demand.

Two other system criteria are also used frequently: 1) adjusted reserves, which are reserve margins changed to reflect the expected impact of maintenance, forced outages, net power transactions, and other factors influencing capacity availability; and 2) capacity margins, which express the difference between demonstrated capacity and peak demand as a percent of total demonstrated capacity instead of as a percent of total peak. The recommended criterion for adjusted reserves is 5 percent.[4] No industrywide standards have been established yet for capacity margins, although the industry appears to be increasing its emphasis on this reliability measure.

[1]Different sources calculate reserve margins differently. For example, NERC includes net capacity transfers in its definition of "demonstrated capacity"; the DOE figures cited in this chapter include net capacity transfers only in the adjusted reserve margin calculations.

[2]Alvin Kaufman and Karen K. Nelson, *Do We Really Need All Those Electric Plants?* (Washington, DC: Congressional Research Service, August 1982), Report No. 82-147 S.

[3]U.S.DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, (Washington, D.C.: DOE, June 1984), DOE/IE-0003.

[4]U.S.DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op.cit., June 1984

than anticipated, these regions—ECAR, ERCOT, MAIN, MAPP, SPP, and SERC—may risk inadequate reserve margins sometime within the next decade, unless supplies in addition to those already planned are secured.[3] This may make short lead time, modular technologies as well as accelerated conservation and load management particularly attractive to some utility systems in these areas. If, on the other hand, future demand is lower than expected, most regions will have excess reserves.

Sensitivity to changes in demand growth increases in regions where substantial numbers of new coal and nuclear plants are already under construction. The 1993 installed capacity levels in four NERC regions—ERCOT, MAIN, SERC, and SPP—are expected to exceed 1983 levels by more than 20 percent (see table 7-4). For three of these regions—ERCOT, MAIN, and SPP—this includes an increase of more than 75 percent in installed nuclear capacity. The oil-dependent NPCC will be increasing its coal capability by about 75 percent, although overall coal capability levels in the region will remain below 20 percent as of 1993. If demand increases faster than anticipated and/or construction delays occur, reserve margins in some of these regions may be adversely affected.[4] If load growth falters below present estimates, however, construction plans may have to be changed, with potentially adverse effects on the financial status of affected utilities.

A 1984 analysis by the U.S. DOE[5] suggests that, since recent operating experience with large generating units (i.e., 500 MW or more) indicates that they tend to be less reliable and require more time for maintenance than small units, a 25 per-

[3]ERCOT and MAPP may prove particularly sensitive, since they are also projected to fall below the 20 percent reserve criterion as well as the 5 percent adjusted reserve benchmark.

[4]For example, a recent study by J. Steven Herod and Jeffrey Skeer of the Office of Coal and Electricity Policy, U.S. Department of Energy projects regional reserve margins through 2000 under two different national demand growth scenarios. The first scenario assumes growth at 2.6 percent through 1990 and 2.4 percent from 1990 through 2000. The second, higher growth scenario assumes 3.3 percent growth through 1990 and 2.9 percent growth from 1990 to 2000, The utility capacity projections used in Herod and Skeer's analysis exclude: 1) coal units planned but not yet under construction as of the end of 1983, and 2) nuclear units only one-third complete as of that date. As would be expected, under these assumptions several regions show reserve margin problems earlier than indicated in figure 7-3. In particular, both ERCOT and MAPP would fall below 20 percent in the mid to late 1980s, highlighting these regions' dependence on planned additions. All regions would fall below 20 percent by 1994 under the high growth scenario. For further information, see J. Steven Herod and Jeffrey Skeer, "A Look at National and Regional Electric Supply Needs, "presented at the 12th Energy Technology Conference and Exposition, March 1985. The views expressed in the report are those of the authors.

[5]U. S. Department of Energy (DOE), *Electric Power Supply and Demand for the Contiguous United States 1984-1993* (Washington, DC: DOE, June 1984.

Table 7-1.-Utility Type, By Region

Census region	NERC regions fully or partially included	Number of IOUs	Number of publicly owned utilities	Percent total electricity sales to ultimate customers from IOUS, by census region, 1983	Percent total electricity sales to ultimate customers from publicly owned utilities, by census region, 1983
New England	NPCC	24	43	91	9
Middle Atlantic	NPCC, MAAC, ECAR	23	49	92	8
East North Central	ECAR, MAIN, MAPP	40	165	90	10
West North Central	MAPP, SPP	34	217	64	36
South Atlantic	ECAR, MAAC, SERC	31	152	81	19
East South Central	ECAR, SERC	9	138	36	64
West South Central	ERCOT, SPP	24	113	81	19
Mountain	WSCC	27	52	70	30
Pacific	WSCC	14	55	62	39
Total, United States		226	984	76	24

NOTES: Totals may not equal 100 percent due to rounding.
IOU = Investor-owned utility.

SOURCE: Office of Technology Assessment, from Energy Information Administration, *Typical Electric Bills January 1, 1984* (Washington, DC: U.S. Department of Energy, December 1984), DOE/EIA-0040(84); and Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, 1984).

cent margin may not completely assure system reliability in those systems which place heavy emphasis on large plants, Whether or not this will emerge as an issue remains unclear; as of 1980, ECAR, ERCOT, MAAC, and SERC were the only regions with more than 15 percent of total capacity in units equaling or exceeding 500 MW; of these regions, ERCOT had the highest percentage–25 percent.[6]

Opportunities for Consumer Side Alternatives to New Capacity

Conservation

Conservation can offer a cost effective alternative to a significant quantity of new capacity construction, and the National Association of Regulatory Utility Commissioners (NARUC) is actively encouraging utilities across the country to include conservation in their resource plans. From a utility's perspective, one of the major issues associated with relying on this "consumer side" supply strategy is that implementation depends on actions outside the utility's direct control. While different pricing strategies have been used to encourage conservation, customer responses are not entirely predictable. Utilities are also concerned about conservation efforts which might reduce off-peak demand without affecting the peak, thereby decreasing system load factor without decreasing the need for new capacity.

The energy conservation resource appears quite large, although estimates of the potential energy savings and capacity deferrals vary widely. OTA'S assessment of conservation opportunities in specific energy-use categories can be found in several previous studies.[7]

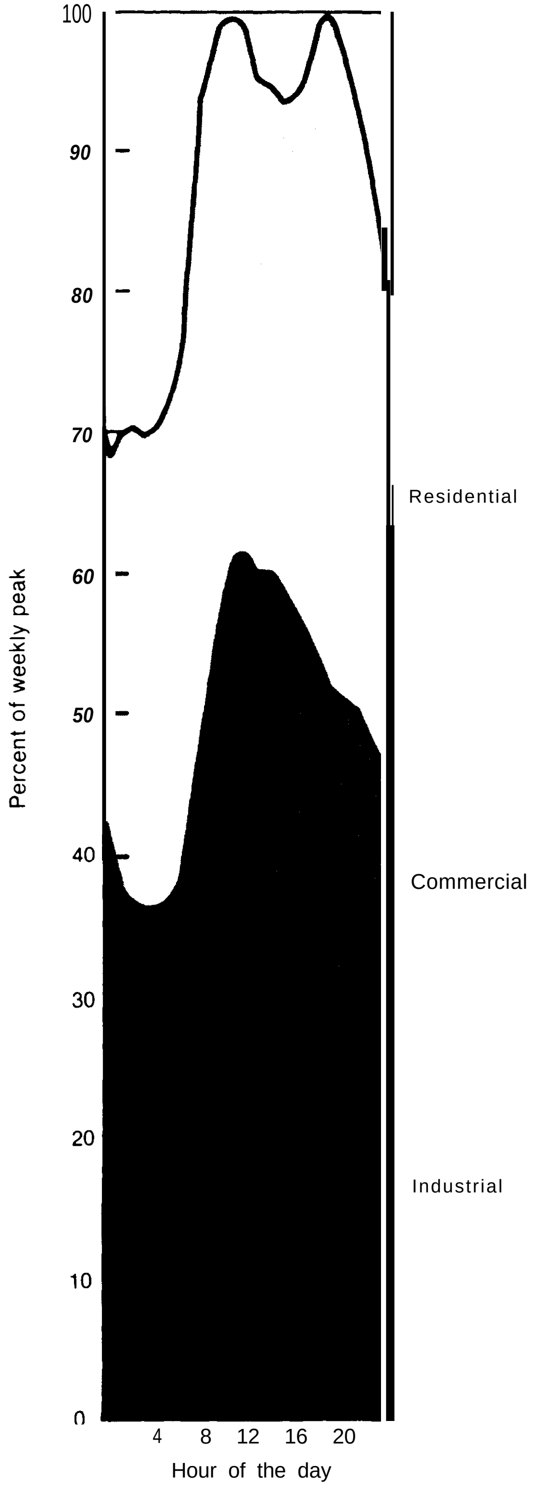
Load Management

NARUC is also encouraging U.S. utilities to consider load management in their resource plans, Load shape patterns define the opportunities for load management, As figure 7-4 illustrates, these patterns differ among end-use sectors, with industrial loads generally more uniform than commercial or residential ones. Load shape variations between utility systems within NERC regions are as marked as the variations among regions. The load management opportunities within a given region are defined by many factors, including system reserve margins, expected load factors, customer profiles, the degree to which a utility generates its own power or purchases it from other systems, and public utility commission policies.

[6]Derived from generating plant database prepared for OTA in January 1985 by E.H. Pechan & Associates, Inc.

[7]U. S. Congress, Office of Technology Assessment (OTA), *Energy Efficiency of Buildings in Cities* (Washington, DC: U.S. Government printing Office (GPO), March 1982); OTA, *Industrial Energy Use* (Washington, DC: GPO, June 1983); OTA, *U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability* (Washington, DC: GPO, September 1984.)

Figure 7.4.— Sample Load Curve for a Utility in the ECAR Region on a Day in January



SOURCE: Office of Technology Assessment, from James J. Mulvaney, "Assessment of R&D Benefits for the Electric Power Industry," Joint National Meeting, ORSA/TIMS, San Diego, CA, Oct. 26, 1982.

One of the key operational objectives behind load management is to increase system load factor–the ratio of average load to total load over a specified time interval. In the united States, regions with high load factors are generally characterized by moderate, stable climates and/or heavy industrial loads, while low load factors usually are indicative of high seasonal peaks in electricity use and/or little heavy industry.[8]

In all regions, there appear to be substantial opportunities for load management; these opportunities are discussed in detail in chapter 5. In particular, the residential market remains largely untapped, making areas characterized by high population density or high population growth attractive candidates (see table 5-l) if the obstacles discussed in chapter 5 can be overcome. Opportunities also remain in the commercial and industrial sectors.

In the long run, fuel reliance patterns may make load management an unattractive option in some regions if it defers replacement of costly oil- or gas-fired units.[9] This may be especially important in oil- or gas-dependent areas such as ERCOT, MAAC, NPCC, SPP, the Florida subregion in SERC, and two subregions of WSCC–the California-Southern Nevada Power Area and the Arizona New Mexico Power Area. From the consumer's standpoint, the deciding factor regarding the desirability of such deferrals will be the ultimate impact on electricity bills—a function of both electricity rates and electricity use. For utilities, the desirability of such deferrals will be heavily influenced by their cost relative to other electricity supply options.

Municipal utilities (munies) and rural cooperatives (coops), most of which buy the bulk of their power from other systems, are already actively pursuing load management to both improve load factor and minimize the cost of purchased power. These systems accounted for one-third of all the load control points in 1983. Munies and coops facing high demand charges on purchased power are expected to continue to provide a strong load

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[8]NERC, *Electric power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

[9]James J. Mulvaney, planning and Evaluation Division, Electric Power Research Institute, *Electric Generation System Development: An Overview,* November 1983.

Table 7-2.—Average Fuel Prices, By Region (in cents per million Btu)

Region and year	Coal	Residual oil[a] (#6)	Distillate oil[b] (#2)	Gas
ECAR:				
1983	168.1	451.9	625.6	426.9
1984	165.9	460.4	628.9	419.8
ERCOT:				
1983	164.3	503.7	517.9	362.3
1984	156.5	567.3	601.5	358.0
MAAC:				
1983	158.1	464.0	602.5	405.4
1984	166.3	488.0	614.6	434.1
MAIN:				
1983	186.7	605.6	621.4	506.4
1984	180.3	613.1	629.9	474.8
MAPP (U.S.):				
1983	128.8	419.5	596.9	365.9
1984	132.1	453.0	603.9	363.9
NPCC (U.S.):				
1983	194.8	446.8	635.4	395.9
1984	192.5	476.0	637.7	398.1
SERC:				
1983	191.8	427.3	621.0	261.3
1984	191.9	463.2	608.4	332.6
SPP:				
1983	166.3	373.8	615.3	251.3
1984	172.6	410.9	625.3	254.6
WSCC(u.s):				
1983	109.4	602.5	619.0	500.5
1984	112.6	620.9	616.2	502.9

[a]Most of the oil burned by utilities (e.g., 90 percent) is residual oil; it is usually burned in base and intermediate load boilers.
[b]Distillate oil is burned in peaking units (i.e., combustion turbines and diesel engines).

SOURCE: Data generated for OTA by Energy Information Administration, Electric Power Division, U.S. Department of Energy, November 1964.

management market through the 1990s in all regions. As suggested by the data presented in table 7-1, load management efforts may be particularly strong in the East South Central, Pacific, West North Central, and Mountain census regions—regions where publicly owned utilities serve significant portions of the electricity market.

Emphasis on load management and/or conservation has been particularly strong in several States, including Nevada, California, Florida, Wisconsin, New York, North Carolina, and the Pacific Northwest (Idaho, Montana, Oregon, and Washington).

REGIONAL ECONOMIC AND REGULATORY CHARACTERISTICS AFFECTING TECHNOLOGY CHOICES

Rate Regulation Issues

Avoided Cost

Potential markets for many new generating technologies depend on the buy-back rates being offered by utilities under the avoided cost guidelines of the Public Utility Regulatory Policies Act (PURPA). Regional generalizations about these rates are complicated by the substantial variations within regions as well as the continued changes in rate offerings, primarily due to fluctuating projections of the costs of avoided fuel use,

Since fuel costs are a critical factor in the economics of technology alternatives, regional averages are presented in table **7-2.** As this table illustrates, fuel costs are particularly high in NPCC and WSCC, two areas within which avoided cost rates are also high relative to the rest of the country. In general, the highest avoided energy rates (as of October 1984) were offered in NPCC, WSCC, ERCOT, and MAAC, with utilities in States in each of these regions offering rates equal to or above 6 cents/kWh. With the exception of Florida (SERC), States within these four regions were also the ones with utilities offering the highest capacity credits.[10]

[10]From data presented in "'States' Cogeneration Rate-Setting Under PURPA, Part 4," *Energy* User News, vol. 9, Nos. 40-43, Oct. 1, 8, 15, and 22, 1984

Table 7-3.—Average Residential, Commercial, and Industrial Electricity Prices, By Census Region

Census region	NERC regions totally or partially included by designated census regions	Residential rates[a] (¢ per kWh)		Commercial rates[b] (¢ per kWh)		Industrial rates[c] (¢ per kWh)	
		As of 1/1/83 bills	As of 1/1/84 bills	As of 1/1/83 bills	As of 1/1/84 bills	As of 1/1/83 bills	As of 1/1/84 bills
New England	NPCC	08.2	08.9	09.9	10.7	07.8	08.6
Middle Atlantic	NPCC, MAAC, ECAR	09.4	09.5	13.1	13.3	11.5	11.0
East North Central	ECAR, MAIN, MAPP	06.6	06.9	08.4	08.7	07.6	07.8
West North Central	MAPP, SPP	05.9	06.3	06.7	07.1	05.7	06.1
South Atlantic	ECAR, MAAC, SERC	06.5	06.9	07.3	07.5	06.8	07.1
East South Central	ECAR, SERC	05.5	0.56	06.3	06.3	06.1	06.1
West South Central	ERCOT, SPP	06.3	06.7	07.1	07.5	06.1	06.7
Mountain	WSCC	06.3	06.4	07.5	07.4	06.2	06.3
Pacific	WSCC	06.4	06.5	07.6	07.7	07.3	07.4

[a]Residential rates based on monthly usage of 750 kWh.
[b]Commercial rates based on monthly usage of 6,000 kWh (30 kW demand).
[c]Industrial rates based on monthly usage of 200,000 kWh (1,000 kW demand).

SOURCE: OTA, from Energy Information Administration (EIA), *Typical Electric Bills January 1, 1984* (Washington, DC: U.S. Department of Energy, December 1984), DOE/EIA-004C84; Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983 (Washington, DC: EEI, 1984); and 1984 data on commercial and industrial rates supplied by EIA's office of Coal and Power Statistics.*

While avoided cost rates could fall in the near term (e.g., due to declining oil and gas prices) there is considerable disagreement on this issue.[11] As a policy decision to encourage cogeneration and new technologies, some State regulatory agencies (e. g., New York, New Jersey, and Iowa) are deliberately establishing or encouraging high buy-back rates.[12] These actions have often been the impetus for litigation; the Iowa rate was being challenged in court at the time this report went to press, while the New York rate had just avoided further challenge when, based on jurisdictional issues, the Supreme Court declined to review a lower court's decision upholding the rate.

Construction Work in-Progress

State policies towards construction work in-progress (CWIP) for new generating facilities are another factor which may strongly influence technology choices. Allowing CWIP in the ratebase helps avert the sudden rate shocks which can occur when major new plants come into operation; this assumes added importance in areas such as the New England and Mid-Atlantic States (see table 7-3) where electricity rates are already high relative to the rest of the country. Allowing CWIP in the ratebase can also make it easier for utilities to obtain financing for new construction projects, since this reduces the perceived and actual financial risks associated with new construction. Conceivably, such a policy could encourage all types of technology, but industry observers suggest it is most likely to favor conventional technologies—systems with which utilities are the most familiar and comfortable (see chapter 3 for a more detailed discussion).

Handling CWIP in retail rates is a State decision; rate policies are highly variable both between States and within the same States over time.[13] As of 1981, about 50 percent of all State regulatory agencies allowed some form of CWIP in the ratebase.[14] The Federal Energy Regulatory Commission (FERC), which controls wholesale rates, allows 50 percent of the funds used for construction to be treated as CWIP.

Licensing and Permitting of Small-Scale Systems

Because the economics of small or undercapitalized projects are particularly vulnerable to unanticipated costs or delays, regulatory policies affecting facility siting can also have a strong impact on technology deployment, especially when third-party producers are involved. To date, most of the experience in licensing and permitting small-scale alternative (especially renewable) technology projects has been in California. Although California's environmental review process is unique and perhaps the most rigorous in the country, some general trends appear to be emerging. Of these, the most important is that new, small-scale (i.e., less than 50 MW) technologies are not immune to controversy and opposition. While their impacts tend to be localized, concerns about them have in some cases led to lengthy and expensive environmental review, with the review costs borne by the developers. In other cases, the same types of projects have met no local resistance at all (see box 76).

These experiences suggest that implementation of small-scale solar, geothermal, and wind technologies will be substantially influenced by local regulatory policies, the most influential being local zoning ordinances, land use permits, and public health standards. In areas where a land intensive project is proposed and sensitive habitat is affected, State and Federal laws may assume a dominant role, but these effects will be more site than region specific.

While siting of alternative technologies can be expected to be carefully monitored, especially in States with strongly protective environmental

[11] OTA workshop on Economic and Regulatory Issues Affecting New Generating Technologies, February 1985.

[12] Some industry observers also note that several utility commissions are beginning to react against high avoided cost rates and may move to set artificially low rates in an effort to protect their ratepayers. Other States such as California are stepping back from long-term levelized rates and returning to annual ones. Source: Allen Clapp, Director of Financial and Economic Analysis, North Carolina Alternative Energy Corp., personal communication, November 1984,

[13] For example, the Texas Public Utility Commission allowed CWIP in the rate base in 1980, but a subsequent 1984 ruling excluded it.

[14] Energy Information Administration, *Impacts of Financial Constraints on the Electric Utility Industry* (Washington, DC: December 1981), DOE/EIA-0311.

Table 7-4.—Selected Characteristics of Regional Electric Utility Generation Systems

Region	Demand growth (%) 1984-93	Planned additions (%)[a] 1984-93	Fuel reliance: Percentage of total generating capability — Coal ≥25% 984	Coal ≥25% 1993	Coal ≥45% 1984	Coal ≥45% 993	Nuclear ≥15% 1984	Nuclear ≥15% 993	Nuclear ≥25% 1984	Nuclear ≥25% 1993	Oil and Gas ≥25% 1984	Oil and Gas ≥25% 1993	Oil and Gas ≥50% 1984	Oil and Gas ≥50% 1993	Years of projected failure to meet target reserve margins[b] 25%	20%	5% (adj.)[c]
ECAR	2.4	14.4															'92-'93
ERCOT	4.0	40.1	•	•							•	•	•		'84-93	'88, '90-93	'91-93
MAAC	1.3	9.5	•	•			•	•		•	•	•					
MAIN	1.8	22.4	•	•	•	•	•	•		•					'83-84, '93		'86, '91-93
MAPP	2.4	11.5	•	•	•	•									'87-93	'90-93	'92-93
NPCC	1.7	14.0					•	•			•	•	•				
SERC	2.9	21.9	•	•	•	•	•	•									93
SPP	2.7	21.3	•	•							•	•	•		[illegible]-93		
WSCC	2.6	17.6		•							•						

[a]Expected increase over 1983 capacity.
[b]Based on currently planned additions reported to NERC; power transfers not included
[c]Adjusted to account for maintenance and other planned outages.

SOURCE: Office of Technology Assessment, prepared from data presented in U.S. Department of Energy, *Electric Power Supply and Demand for the Contiguous United States 1984-1993* (Washington, DC: U.S. Department of Energy, June 1984), DOE/1E-0003; and North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ; NERC, 1984).

policies, the relatively less severe environmental impacts associated with many of the new technologies considered by this report may result in siting policies designed to encourage their development within specific guidelines.

[illegible]

[illegible] These factors appear to be potentially applicable in other states as well; for example, development of a windfarm in the Shawangunk Mountains near Ellenville, New York, already has met substantial delay due to concerns about the facility's visual impacts.

KEY CHARACTERISTICS OF REGIONAL ELECTRICITY SUPPLY SYSTEMS

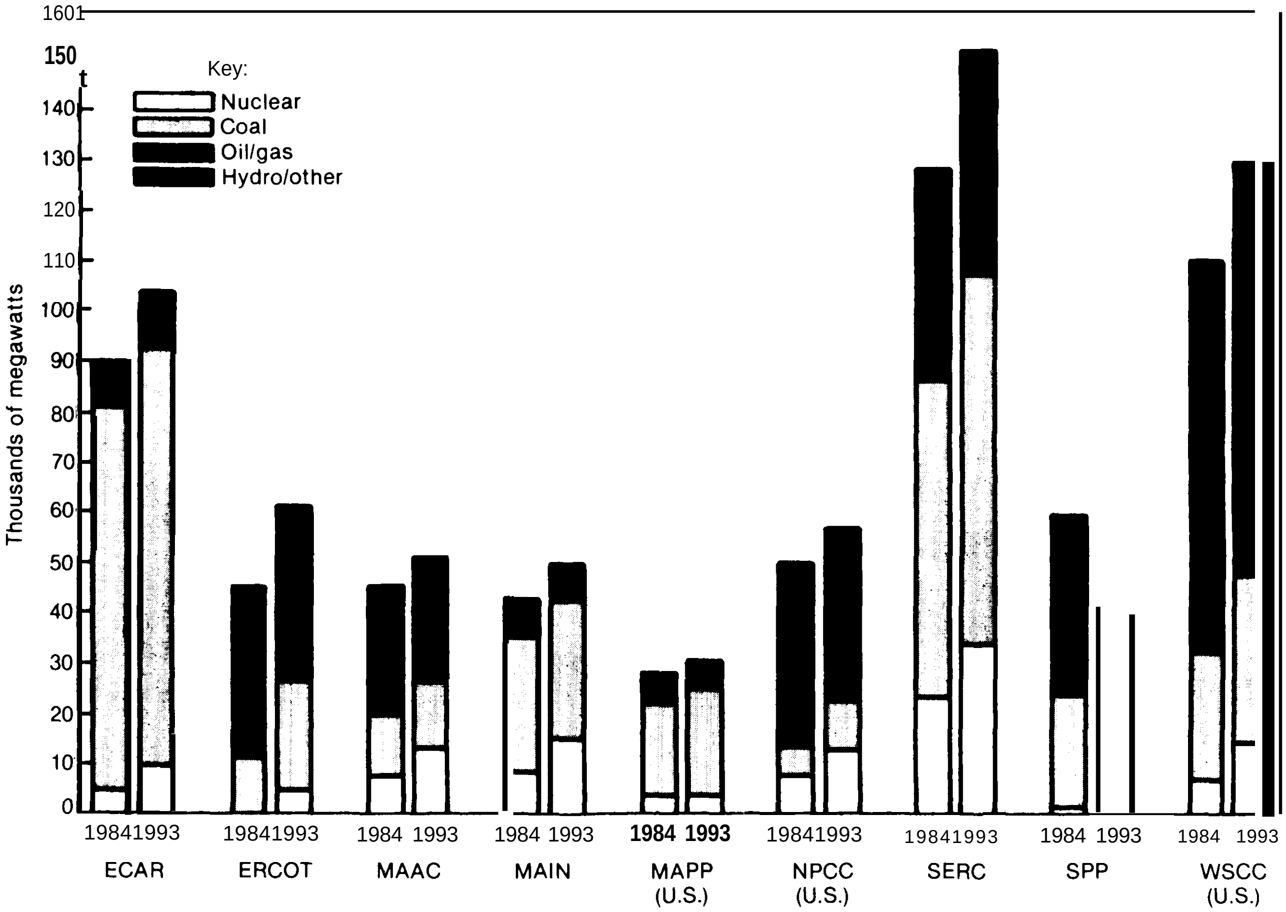
Present and Projected Fuel Reliance

Regional fuel and technology reliance establish the benchmarks for technology cost comparisons. While most systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, reliance on premium fuels is expected to be strong enough in some areas, i.e., ERCOT, MAAC, NPCC, and some subregions of SERC, SPP, and WSCC, that the economics of competing technologies will remain particularly sensitive to the price and availability of oil and gas (see figures 7-5 and 7-6, and table 7-2).[15] As discussed in the section on demand uncertainty, this sensitivity will be heightened if there are significant changes in actual demand

[15]These fuel reliance projections are from NERC, *Electric Power Supply and Demand, 1984-1993,* op. cit., 1984; and from NERC, *14th Annual Review,* op. cit., 1984

The reader should note that all of the 1984 figures cited from these two NERC documents are *projections* made by the reliability councils in early 1984 (i. e., January-April).

Figure 7-5.—Regional Utility Capacity by Fuel Use, 1984 and 1993



SOURCE: Office of Technology Assessment, from data presented in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Trenton, NJ: NER~; 1984).

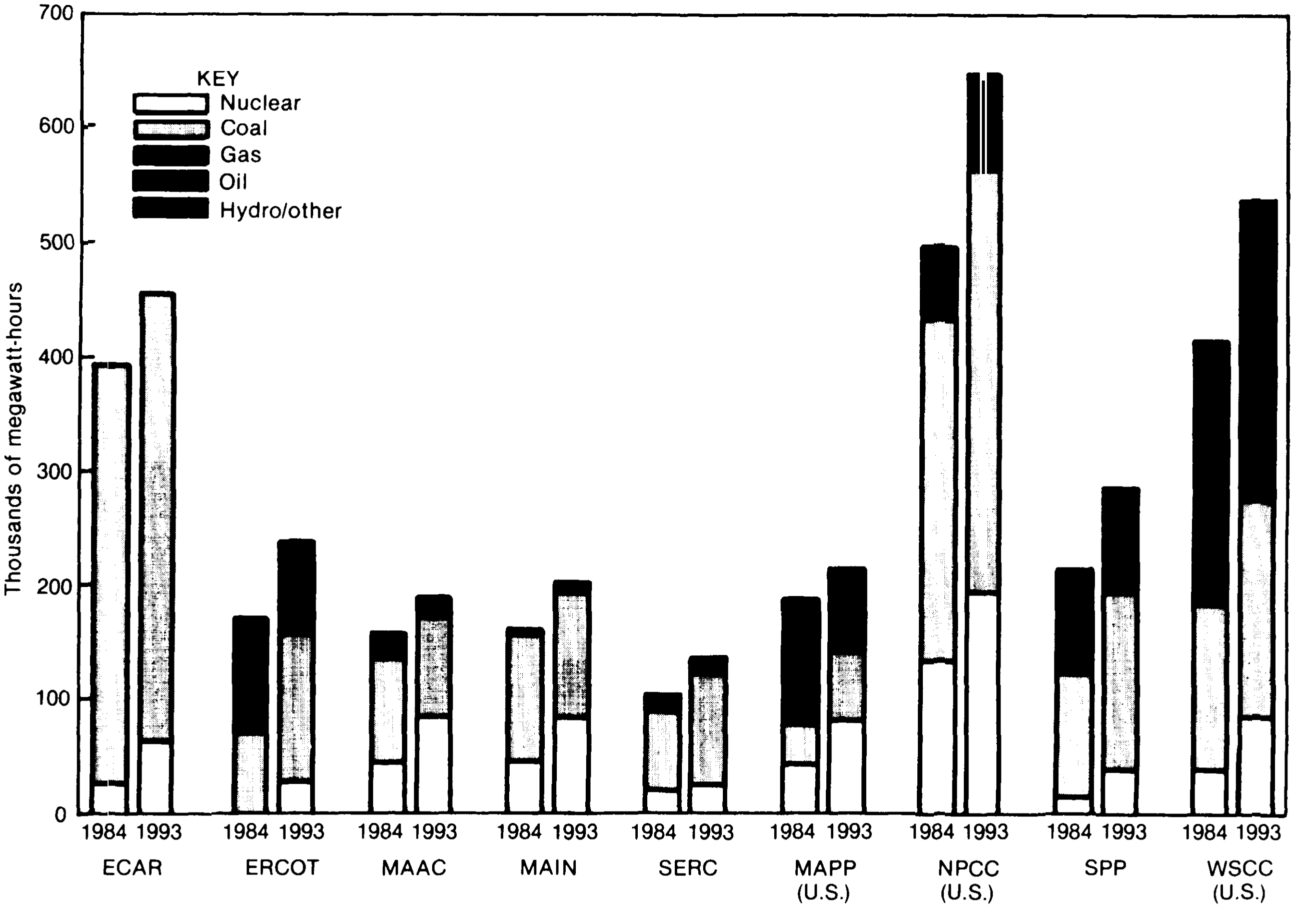
growth requiring either cancellation of plants under construction or rapid construction of new capacity. These issues are more fully described in the regional profiles.

Opportunities for Plant Betterment and Life Extension

If scheduled retirement of aging powerplants can be delayed by plant rehabilitation or efficiency improvements, the need for new construction may be deferred. As table 7-5 illustrates, deferral prospects vary considerably by region. At least 40 percent of the fossil-fired steam plants in the MAIN, NPCC, and WSCC regions will be over 30 years old by 1995, making life extension a potentially attractive option. In terms of total capacity, the opportunities for life extension appear highest in ECAR, SERC, SPP, and WSCC.

Having a large number of older plants does not mean life extension or plant betterment will be the most cost-effective supply enhancement option; as discussed in chapter 5, choosing this option will depend on site-specific economics. Nonetheless, the resource scope alone promises to make it an important factor affecting regional adoption of new technologies; in all but one region, the life extension base exceeds regional capacity additions planned for the decade of 1983-93.

Figure 7-6.– Regional Utility Generation by Fuel Use, 1984 and 1993



SOURCE: Office of Technology Assessment, based on data presented in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Trenton, NJ: NERC, 1984).

Table 7-5.—Life Extension Resource Base: Age of Fossil-Fired Steam Plants, By Region

Region	Percent FF capacity ≥30 years old as of 1995	Total installed FF capacity ≥30 years old as of 1995 (MW)	Total utility plant capacity additions planned for 1993 over 1983 installed levels (MW)
ECAR	32.9	33,335	13,083
ERCOT	20.4	12,186	17,546
MAAC	35.5	11,589	4,435
MAIN	41.3	14,172	9,157
MAPP (U.S.)	25.8	6,695	3,203
NPCC (U.S.)	52.6	16,806	7,082
SERC	35.8	32,239	27,348
SPP	30.0	21,359	12,646
WSCC (U.S.)	39.5	24.811	19,630

KEY: fossil-fired steam plants.

SOURCE: Office of Technology Assessment, from data generated by E. H. Pechan & Associates, December 1984; and North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993,* (Trenton, NJ: NERC, 1984).

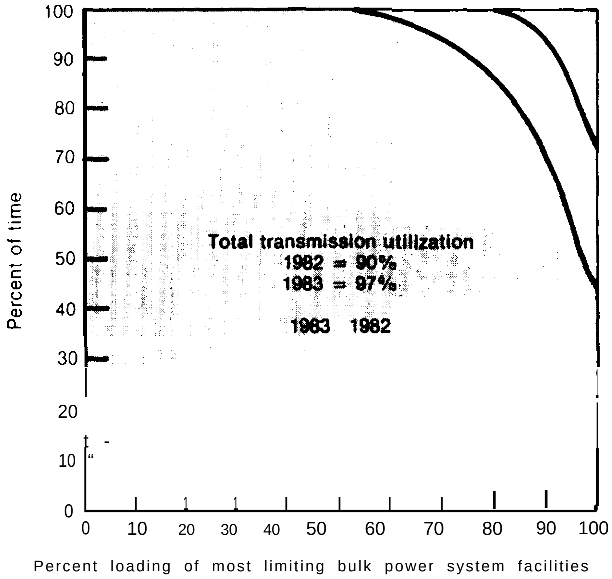
Supply Enhancements From Interregional and Intraregional Power Transfers

The amount and importance of interregional and intra regional power transfers has increased dramatically over the past four decades. While such transfers historically have been used to increase overall system reliability (i. e., emergency transfers to support energy-deficient areas during emergencies), the more recent emphasis has been on economy transfers which displace high cost, fossil fuel generation with cheaper electricity from neighboring systems. This trend has led many transmission systems to be consistently operated at or near maximum secure loading levels. In systems throughout the country, high loading levels are now raising concern about impacts on overall system reliability. Related physical transmission limits are curtailing economically attractive exchanges into many oil- and gas-dependent regions.[16]

The situation in MAAC, where considerable amounts of energy are imported from ECAR and SERC, highlights these growing problems. In 1982, MAAC's most limiting bulk power facilities were loaded to full capacity 40 percent of the time; 1 year later, this climbed to 70 percent. In that same year (1 983), the system was used at 90 percent of rated capacity almost 95 percent of the time[17] (see figure 7-7). When systems are used at this intensity, their ability to respond to u nexpected, severe disturbances is reduced, thereby increasing the risk of service interruption.

Rather than increasing reliability through redundancy, i.e., building new power lines, utilities are responding by developing more sophisticated protective relaying schemes and operating procedures. Some engineers argue that the net result of this new trend may be increased load shedding, indicating acceptance of increased risk of customer service interruptions (perhaps at preselected sites) when it results in net economic gain.[18] A combination of factors probably underlies this new trend, including anticipation of continued escalation of construction costs, interest rates, and fuel costs, as well as public opposition to (and the regulatory complexity of) building new plants or new transmission lines.[19]

Figure 7-7.—Historical Transmission Loading Patterns in MAAC



SOURCE: North American Electric Reliability Council (NERC), *14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America, 1984* (Princeton, NJ: NERC, 1984), p. 18.

Figure 7-8 summarizes power transfer capabilities among regions; table 7-6 shows expected net import/export levels by region through 1993 (these are relatively long-term "firm capacity" exchanges set by contract; economy transfers are far more variable and predictions regarding their regional levels are not included). In general, if demand growth follows present predictions and current construction plans are implemented, utilities with large amounts of coal-fired generation probably will continue to be net exporters of power, while systems trying to reduce use of expensive-to-operate oil and gas units will be net purchasers of cheaper power–if they have access to it. However, it is unlikely that power transfers will be a substantial source of alternative capacity in many NERC regions due to the heavy use of existing transmission capacity, the limited

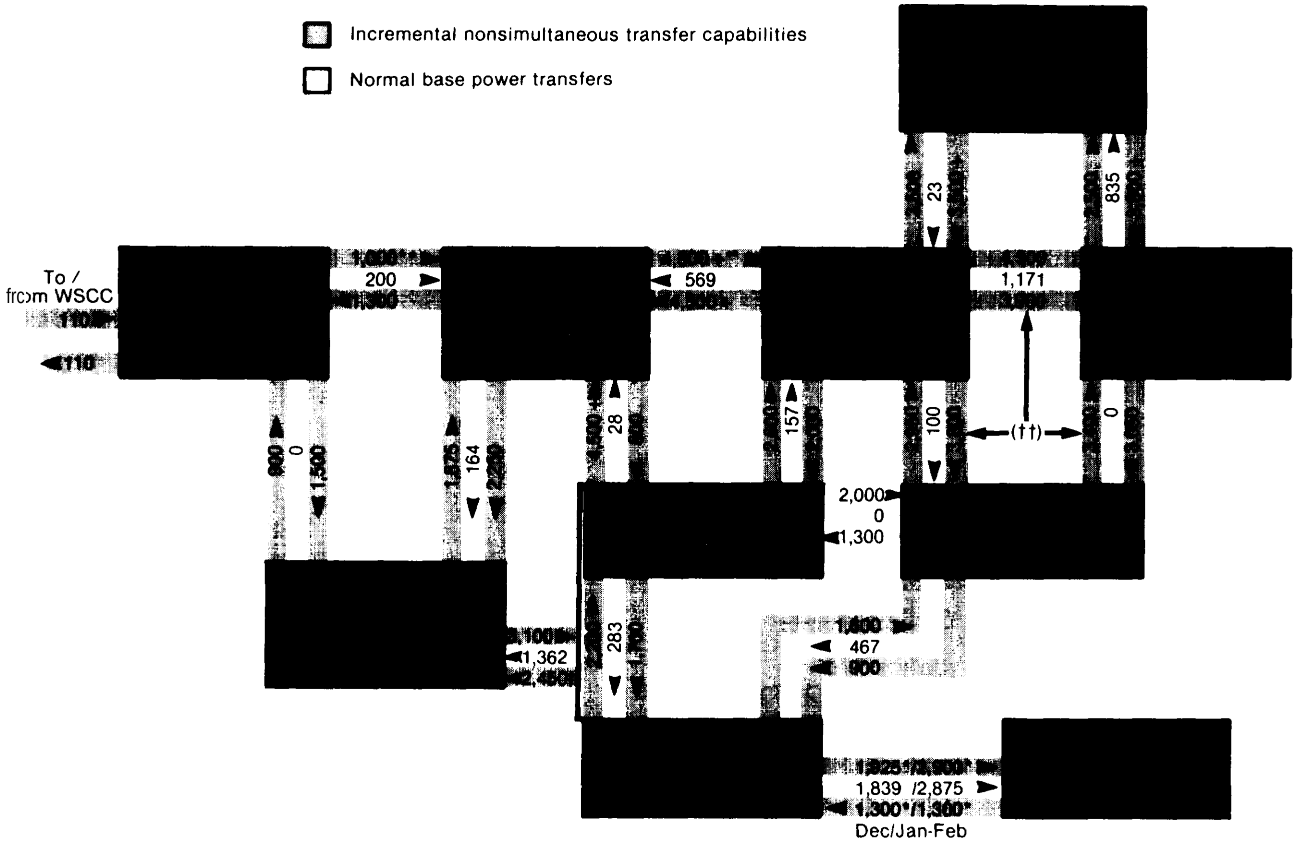
[16] NERC, *14th Annual Review,* op. cit., 1984; and Energy Information Administration, *Interutility Bulk Power Transactions* (Washington, DC: U.S. Department of Energy, October 1983), DOE/EIA-0418.

[17] NERC, 74th *Annual Review,* op. cit. , 1984.

[18] 1 bid.

[19] EIA, *Interutility Bulk Power Transactions,* op. cit., 1983.

Figure 7-8.—Interregional and Intraregional Power Transfer Capabilities



(†) With no additional import into the South Louisiana Area of SPP.

††) The transfer capabilities between ECAR, MAAC and VACAR are preliminary values taken from ongoing studies. These capabilities are based on thermal limits only. Voltage limitations may cause certain of these capabilities to be lowered.

• Total amount of power that can be transferred in a reliable manner.

" • With a specific operating procedure in effect.

(+) No significant transmission limit at this level.

SOURCE: North American Electric Reliability Council (NERC), *1984/85 Winter Assessment of Overall Reliability of Bulk Power Supply in the Electric Utility Systems of North America* (Princeton, NJ: NERC, Nov. 15, 1984), p. 16.

number of new lines scheduled for operation within the next decade, and the long lead times associated with siting additional lines. The few exceptions are discussed in the regional profiles.

Prospects for Nonutility Generation

Cogeneration

A 1983 OTA assessment estimated the technical cogeneration potential in the United States by the year 2000 at 200,000 MW in the industrial sector and 3,000 to 5,000 MW in the commercial, agricultural, and residential sectors. Actual implementation is expected to be considerably less, depending on a broad range of economic and institutional considerations.[20] For example, if a 7 percent rate of return after inflation is used as the cut-off point for acceptable project economics a 1984 study prepared for

[20] U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E-192.

Table 7-6.—Actual and Expected Power Transfers, 1983-93°

Region	Years expected to be net exporter	Net exports (range in MW) Low	High	Years expected to be net importer	Net imports (range in MW) Low	High
ECAR	1984-92	270 summer 1992	3,938 summer 1994	1993	175 winter 1993	178 summer 1993
ERCOT	0	0		1984-93	582 winter 1986 summer 1987	709 winter 1989
IvIAAC	0	0		1984-93	107 winter/ summer 1993	1,582 winter/ summer 1984
MAIN	1985-93	65 summer 1993	536 winter 1989	1984	42 winter 1984	462 summer 1984
MAPP (U. S.)	1984-92 winters	354 winter 1984	658 winter 1986	1984-93 summers	327 summer 1987	556 summer 1993
NPCC (U. S.)	Winters of 1991, 1992, 1993	81 winter 1991	101 winter 1993	1984-93	77 winter 1990	1,747 summer 1985
SERC	1984-89 winter summer	300 summer 1985	1,540, winter 1984	summer 1984; 1989-93	200 winter 1989- winter 1991	1,300 winter 1992
SPP	1992-93	240 summer 1993	539 winter 1993	1984-92	226 winter 1984	1,017 summer 1987
Wscc (Us.)	0	0		1984-93	183 winter 1984	610 winter 1983

aFirm power transfers only; economy purchases are not included.

SOURCE: Office of Technology Assessment, from U.S. Department of Energy (DOE), *Electric Power Supply and Demand for the Contiguous United States, 1983-1993* (Washington, DC: DOE, June 1984), DOE/IE-003.

DOE[21] estimates that 39,348 MW of industrial cogeneration capacity are presently available. Fifty-four percent of this total is in six States. Three of them—Texas, California, and Louisiana (corresponding to ERCOT, the California-Southern Nevada subregion of WSCC, and the southern portion of SPP) account for 31 percent of the total potential, making these areas especially important in terms of possible contributions from nonutility generators. Pennsylvania, Ohio, and New York (corresponding to parts of ECAR, MAAC, and NPCC) account for an additional 16 percent, making contributions in these States also substantial relative to the country as a whole. The potential is not expected to be high in the New England, Northwest, North Central, and Central DOE regions, although individual States within these regions, e.g., New York, may be exceptions. Table 7-7 presents a summary of the regional cogeneration opportunities identified by the study and lists the States included in each region. These estimates are based on 1980 data; the study projects that 47,435 MW in addition to the 39,348 MW presently available will be available by the year 2000.[22]

While some utilities consider the anticipated impact of power from nonutility generators in their demand forecasts, capacity plans, and other data submitted to NERC for preparation of its annual reports, many others do not. This results in inconsistent treatment and probable underrepresentation of these potential resources by the NERC projections cited in this chapter.

Resource Availability

Regional differences in resource availability will define the range of opportunity for many new technologies considered in this assessment.

As figure 7-9 illustrates, geothermal development is expected to be co~fined to the Southwest and Hawaii

zi Dun &Bradstreet Technical Economic Services and TRW Energy Development Group, *Industrial Cogeneration Potential (1980-2000) for Application of Four Commercially Available Prime Movers at the Plant Site, Final Report,* 1984.

[22]1 bid.

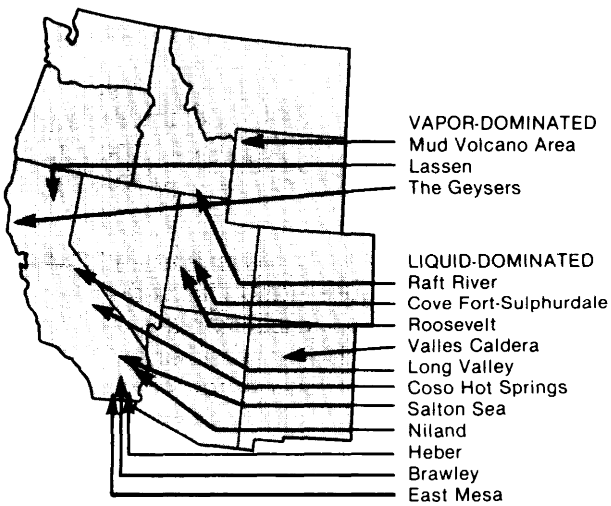
Table 7.7.–Estimated Maximum Industrial Cogeneration Potential Available as of 1980

EIA/DOE region	States included	NERC regions fully or partially included	Percent of potent plants	Percent of total plants nationally	Potential MW	Percent of potential MW nationally
New England	ME, VT, NH, MA, CT, RI	NPCC	189	5	1,690	4
NY/NJ	NY, NJ	NPCC, MAAC	540	15	3,544	10
MidAtlantic	PA, DE, MD, VA, WV	MAAC, ECAR, SERC	470	13	4,155	11
South Atlantic	KY, TN, NC, SC, GA, AL, MS, FL	SERC, SPP, ECAR	679	19	6,368	16
Midwest	WI, MI, IL, IN, OH	MAIN, ECAR	850	23	6,255	16
Southwest	TX, OK, NM, LA, AR	ERCOT, SPP, WSCC	348	10	9,442	24
Central	IA, NE, MO, KS	MAPP, MAIN, SPP	121	3	1,553	4
North Central	ND, SD, MT, WY, UT, CO	WSCC, MAPP	28	1	736	2
West	CA, NV, AZ, HI	WSCC	359	10	4,241	11
Northwest	WA, OR, ID, AK	WSCC	60	2	1,360	4
		Total	3,644	[a]	39,344	[a]

[a]Totals exceed 100 percent due to rounding.

SOURCE: Office of Technology Assessment, from: 1) Dun & Bradstreet Technical Economic Services and TRW Energy Development Group, *Industrial Cogeneration Potential (1980-2000) for Application of Four Commercial Available Prime Movers at the Plant Site, Final Report*, vol. I, prepared for U.S. Department of Energy, Office of Industrial Programs (Springfield, VA: National Technical Information Service, August 1984), DOE/CS40403-1; and 2) information provided to OTA by the U.S. Department of Energy, April 1985.

Figure 7-9.— Major U.S. Hydrothermal Resources



SOURCE: Peter D. Blair, et al., *Geothermal Energy: Investment Decisions and Commercial Development* (New York: John Unley & Sons, 1982), p. 9. Reproduced from R L. Smith and t-i. R. Shaw, U.S. Geological Su'wey Circular 76, 1975.

While the wind resource is strong in the West (WSCC) and most of the development to date has occurred there, the resource is promising in many other areas, including parts of ERCOT, MAPP, NPCC, and SPP (figure 7-10).

"incompatible" land uses may limit the land-intensive wind and solar technologies, especially in areas where a high premium is placed on visual esthetics (see the earlier discussion on licensing and permitting). In densely populated regions such as NPCC, development of these technologies may be more affected by land availability rather than by resource availability, For example, solar electric development will be particularly constrained in heavily populated areas where insolation levels require high acreage per kilowatt of power production. Figure 7-1 iillustrates the national solar resource .23

While land availability constraints may limit solar and wind development, these same constraints are expected to augment the attractiveness of fuel cells and batteries in urban areas. Resources for CAES development are available in all regions, as illustrated in figure 7- l 2.

Regions projecting continued and/or expanded emphasis on coal generation (especially ECAR, MAIN, MAPP, and SERC) will be likely candidates for AFBC and IGCC development (see table **7-4).**

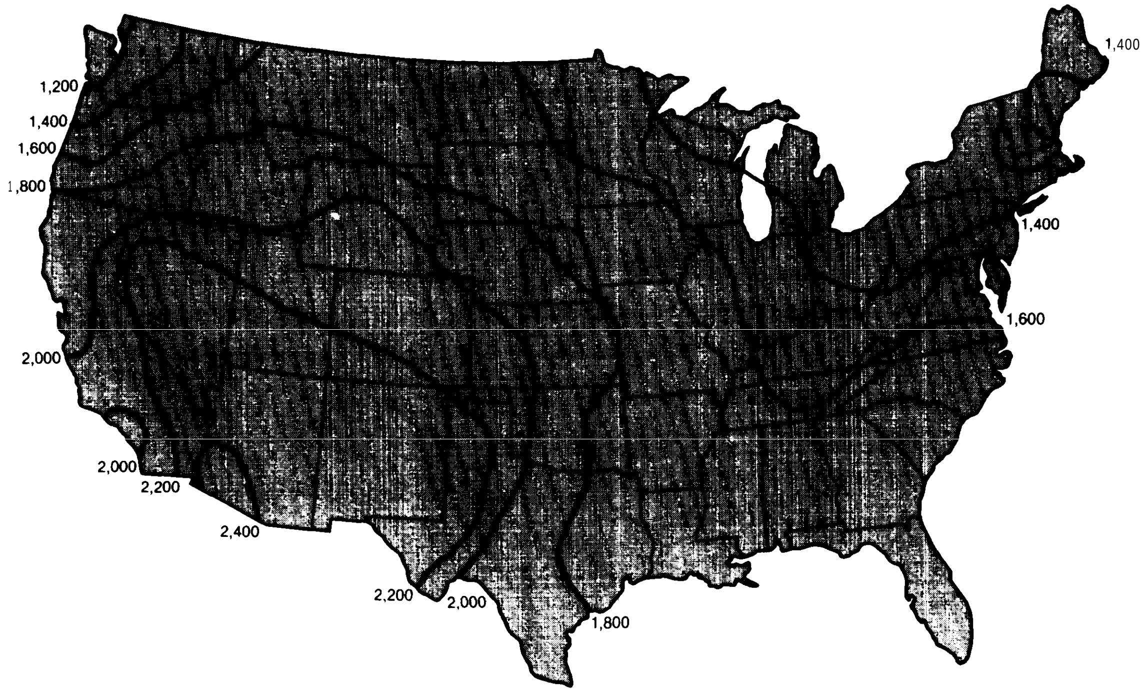
[23]Solar availability i n the United States varies by close to a factor of 2 between the Southwest, on the one hand, and the Northwest and Northeast on the other.

Figure 7-10.—Average Annual Wind Power (watts per square meter)

NOTES: Estimates are for wind speeds at a point 50 meters above land surface. For mountainous areas (shaded), the figures provided are low estimates of wind speeds on exposed ridges or summits.

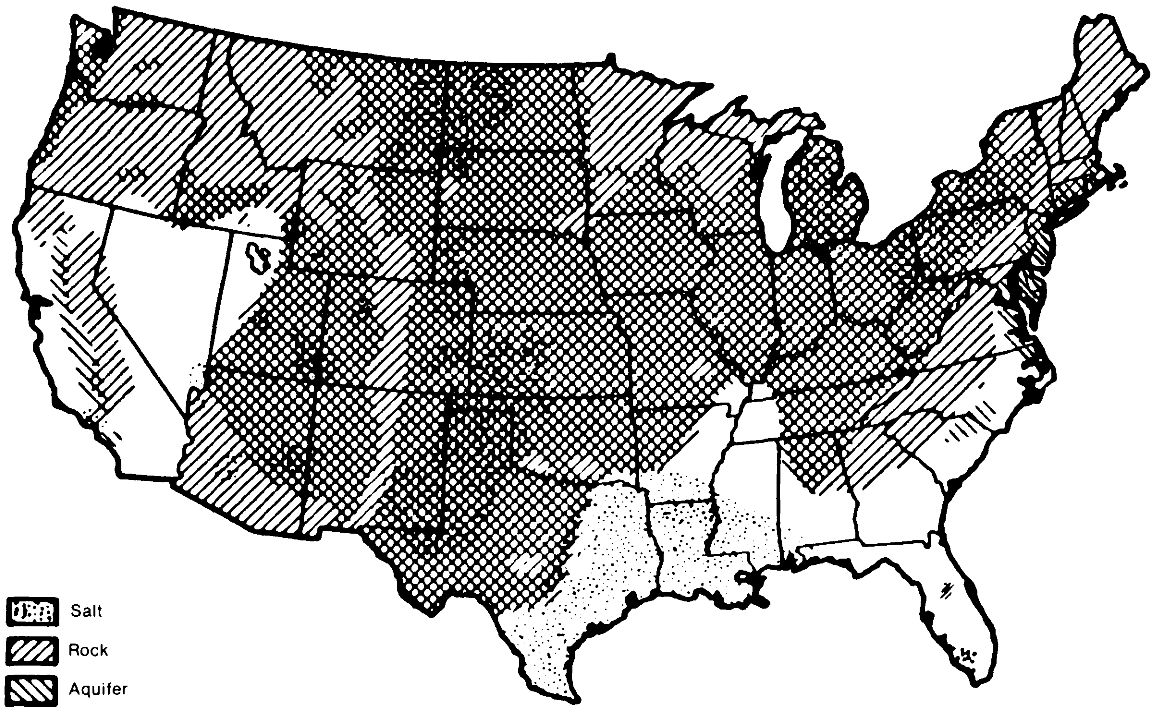
SOURCE: From Kendal and Nadis' *Energy Strategies: Toward a Solar Future*, Copyright 1980, Union of Concerned Scientists, Reprinted with permission from Ballinger Publishing Co.

Figure 7-11.—Average Annual Solar Radiation (kWh/m^2 – yr)



SOURCE: M. G. Thomas and G. J. Jones, "Grid-Connected PV Systems: How and Where They Fit," *Sandia Report: A Compilation of Sandia Contributed Papers to the 17th IEEE Photovoltaic Specialists Conference*, prepared for the U.S. DOE, Edward L. Burgess (ed.) (Albuquerque, NM: Sandia National Laboratories, May 1984).

Figure 7.12.—Geological Formations Potentially Appropriate for Compressed Air Energy Storage



SOURCE: From Robert B. Schainker, *Overview on Compressed Air Energy Storage*, Copyright 1985, Electric Power Research Institute. Reprinted with permission of the publisher.

REGIONAL FUEL AND TECHNOLOGY RELIANCE[24] PROFILES

East Central Area Reliability Coordination Agreement (ECAR)

In anticipation of a 2.4 percent regional annual growth rate in summer peak demand, ECAR is projecting a 14 percent increase in its 1983 installed capacity levels by 1993.[25] The region relies heavily on coal (93 percent of 1984 electricity generation) and is expected to continue this reliance well into the 1990s. Present construction plans also project a substantial increase in dependence on nuclear energy, from 7 percent of total generation in 1984 to 13 percent in 1993.[26] There is a possibility that several of these nuclear plants will not be completed on schedule; member systems have already had to cancel four nuclear units[27] (3,600 MW) which were well along in construction. Two of these (Midland 2 and Zimmer 1) are among the costliest plants in the country.[28]

Assuming completion of presently planned units (i. e., as of the 1984 14th Annual NERC report), ECAR's 1993 reserve margin is currently estimated at 32 percent[29]—well above traditional measures of adequacy, According to the region's 1984 annual report, of the units planned and/or currently under construction, five nuclear units (5,100 MW) scheduled for completion by 1988, nine combustion turbines (735 MW) and three coal plants (1,550 MW) scheduled for completion between 1989 and 1993 may not be finished on schedule, raising some questions about adequate reserves at the end of the decade if demand grows as expected. If these plants are completed on time, 1993 projections for adjusted reserves (4.6 percent) fall slightly below suggested reliability criteria[30] (see table 7-4), while reserve margin estimates remain well above 20 percent. As figure 7-3 suggests, the national high demand growth scenario could lead to reserve shortfalls in the region, while lower demand scenarios leave ECAR with a sizable capacity surplus.

ECAR's heavy dependence on coal makes it particularly vulnerable to the cost of more stringent acid rain regulations. Plant derating, retirement of older units which cannot be economically retrofitted, and increased down-time from maintaining additional flue gas desulfurization equipment could create a need for additional capacity, depending on the emissions reductions required, the age-mix of the plants affected, projected electricity demand in the area, and related factors. Concerns regarding these regulations are expressed in the annual NERC reports for all the coal-dependent regions.[31]

ECAR is characterized by moderate levels of both intraregional and interregional transfers, including power imports from Canada. Within the region, these transfers are due to load diversity; inter-regional sales are economy transfers displacing costlier fuel, especially in the MAAC region. The region is expected to be a net exporter through the early 1990s.[32] ECAR's current transmission system is being used close to its limit; 1,800 miles of new line are under construction to strengthen the region's overall transfer ability.[33]

[24] All of the NERC regional maps included in this section are reprinted with permission from NERC, 14th *Annual Review*, op. cit., 1984.

[25] Historically, ECAR has been winter peaking, but the region is expected to be summer peaking from 1984 on.

[26] NERC, 14th *Annual Review*, op. cit., 1984.

[27] Marble Hill 1 and 2, Midland 1, and Zimmer 1.

[28] According to *Forbes* (James Cook, "Nuclear Follies," *Forbes*, vol. 135, No. 3, Feb. 11, 1985, pp. 82-100), the cost per installed kilowatt at Midland 2 was $4,889, and the cost per kilowatt at Zimmer 1 was at $3,827, compared with an $1,180 cost per kilowatt at Duke Power's McGuire 2 plant.

[29] DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

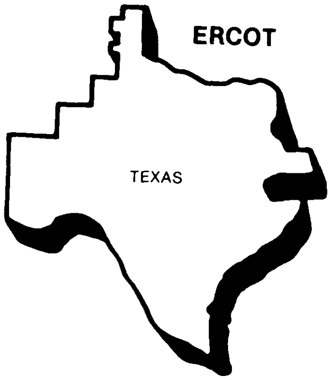
[30] Ibid.

[31] NERC, *14th Annual Review*, op. cit., 1984.

[32] DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

[33] NERC, 14th *Annual Review*, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

Electric Reliability Council of Texas (ERCOT)



Demand is expected to grow at an average annual rate of 4 percent in ERCOT over the next decade—the highest growth rate of all the NERC regions. Member utilities depend heavily on gas (60 percent of total electricity generation in 1984; 'projected to decrease to 35 percent in 1993); they are planning to decrease this dependence by building several thousand megawatts of new coal/lignite and nuclear capacity.[34]

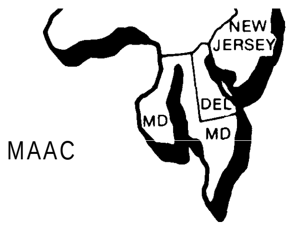
Present utility capacity plans call for a 40 percent increase in installed capacity over 1983 levels by 1993 (see table 7-4). Even with this construction, ERCOT may approach or fall below several suggested reliability criteria within the next decade if present demand predictions prove to be accurate. For example, the adjusted reserve margin is projected to fall to 4.3 percent as of 1991, and the installed reserve margin is expected to fall below 19 percent from 1990 through 1993.[35] Figure 7-3 suggests the region may experience large capacity shortfalls relative to other regions under all but the lowest national growth scenarios.

power from cogenerators could offset possible shortfalls in the region, since potential contributions from cogeneration may be inadequately reflected by current utility resource plans. While the present industrial cogeneration potential in ERCOT is estimated at 5,110 MW,[36] the cogeneration capacity additions shown in the region's 1984 report total 885 MW for the 1984-93 planning period; total capacity contributions from "other" sources for 1993 is estimated at 4,862 MW—this figure includes conservation, load management, energy from refuse, and other undesignated sources as well as cogeneration.[37] In response to the large cogeneration resource in-state, the Texas utilities commission recently ordered one Texas utility to show cause why several planned lignite-fired plants should not be decertified in light of potential capacity from cogenerators.[38]

Whether or not the full cogeneration potential in ERCOT is realized will depend to a large extent on relative economics; it is likely that cogeneration will be one of the major supply options with which new power generating technologies will have to compete.

Imports from other regions are expected to play an increasing role in ERCOT. Historically, there have been large amounts of interchanges among ERCOT member systems, mainly for emergency purposes, but ERCOT has been relatively isolated from other regions. Lines are presently under construction to link ERCOT systems with SPP and better integrate remote generating sources within ERCOT.[39] The region is expected to be a net importer for the next decade (see table 7-6).

Mid-Atlantic Area Council (MAAC)



MAAC utilities rely predominately on nuclear and coal-fired generation. By 1993, nuclear's share of total generation is expected to jump from 28 to 45 percent, while coal's share of generation will drop about 10 percentage points.[40] According to a recent NERC report, the "comparatively

[34] NERC, *14th Annual Review,* op. cit., 1984.
[35] DOE, *Electric power supply and Demand for the Contiguous United States, 1984-1993,* op. cit., 1984.
[36] Dun & Bradstreet and TRW, *Industrial Cogeneration Potential (1980-2000),* op. cit., 1984.
[37] NERC, *14th Annual Report,* op. cit., 1984; and NERC, *Electric Power Supply and Demand, 1984-1993,* op. cit., 1984.
[38] At a recent conference on utility applications for renewable technologies, the vice president of Houston Light and Power noted this fact and also remarked that "We have had 1300 MWe (of cogenerated power) thrust on us over two years. " In addition, in 1984 when the company sought to add 300 MW from third-party producers to boost its reserve margin to 20 percent, cogenerators offered 1,275 MW. (Sources: REI/EEI Conference, op. cit., November 1984; and "Developers, Utilities, Lay Out Their Arguments, " *Solar Energy Intelligence* Report, Nov. 19, 1984, p. 365).
[39] NERC, 74th *Annual Review,* op. cit., 1984; and EIA, *Interutility Bulk Power Transactions,* op. cit., 1983.
[40] NERC, *Electric Power Supply and Demand, 1984-1993,* op. cit., 1984.

weak financial position of some electric utilities in the Region may force decisions to reduce capital expenditures, which will delay the service dates of generating units under construction."[41] Two units (one nuclear, one oil-fired) have already been delayed (the nuclear unit by 2 years, from October 1988 to April 1990; the oil unit from June 1992 to beyond the 1984-93 planning period). MAAC planners cite reduced demand forecasts and financing problems as the major reasons for the delays.

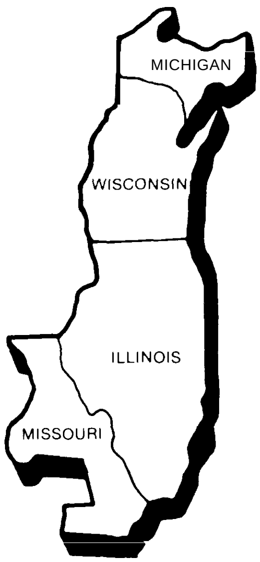
Presently, annual demand growth is predicted to remain at 1.3 percent and reserve margins are expected to be adequate through the early 1990s. As figure 7-3 illustrates, given present construction plans, reserves would fall below 20 percent only under the 4.5 percent national growth scenario. Of course, further plant delays (or unexpected changes in demand growth) could change this situation. The region is already taking maximum possible advantage of economy power transfers from neighboring regions, notably ECAR and SERC; transmission limitations are expected to keep these levels below the amount MAAC utility systems would prefer. These factors may create an attractive climate for short lead time, new technologies if those technologies are economically competitive at the time a need for additional power is recognized.

While only 7 percent of the electricity generated in 1984 in MAAC was expected to be oil-fired (decreasing to 4 percent by 1993), oil and gas comprise nearly 52 percent of MAAC's1984 installed capacity and will probably account for 44 percent in 1993.[42] Oil is the region's "swing" fuel: if circumstances delay construction or in some way impede use of the region's coal and nuclear capacity, or if demand increases substantially faster than expected, oil use will increase. In that case, oil costs will strongly influence the relative economics of alternative generating options.

Like other coal-using regions, MAAC is vulnerable to changes in present environmental regulations. Regional planners note that, if present regulations are substantially tightened, the impact on some of the area's older coal plants could affect overall system reliability, because some units might have to be retired and the output of others would be substantially reduced. This could create a need for additional power sources—another potential opportunity for new technologies.

Nuclear power is another important issue in the region. In particular, developing sufficient away-from-reactor storage facilities for radioactive wastes is a concern for some MAAC utilities which face shortages in onsite storage facilities at some of their older nuclear plants.[43] In the long run, this too may affect technology choices in the region.

Mid= America Interpool Network (MAIN)



MAIN expects its installed capability to exceed 1983 levels by 22 percent in 1993; this construction level is based on a predicted demand growth rate of only 1.8 percent. The region presently relies heavily on coal (68 percent of total electricity generation in 1984) and nuclear power (**29** percent). By 1993, coal is expected to decrease to 56 percent of total electricity generated by electric utilities in the region, while nuclear's share is expected to increase to 41 percent.[44]

Given their emphasis on coal generation, the region's utility systems are sensitive to changes in air emissions regulations. Potential construction delays could also be a problem—85 percent of all of the plants presently under construction in MAIN are nuclear; seven new units are planned to come into commercial service between 1984 and 1987.[45] Delays would be especially important in light of projected reliability criteria for the

[41] NERC, *14th Annual Review*, op. cit., 1984, p. 31.
[42] NERC, *14th Annual Review*, op. cit., 1984.

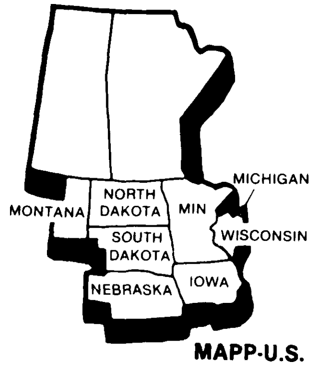
[43] Ibid.
[44] Ibid.
[45] Ibid.

region; as table 7-4 illustrates, given construction plans as of 1984, the area is expected to fall below the 5 percent adjusted reserve margin criterion in the early 1990s. Figure 7-3 suggests further vulnerability under high national demand growth scenarios (i.e., 3.5 and 4.5 percent). Given present oil- and gas-fired capacity levels (15 percent of 1984 capacity; 2 percent of 1984 generation), oil and gas could be "swing" fuels in the region.

MAIN expects to be a net power exporter over the next decade; it is one of the only regions projecting commitment to "surplus" capacity so it can take advantage of economy power sales to neighboring regions.[46] A surplus is also seen as desirable because it would ease routine maintenance schedules by removing some of the pressure to get a unit being serviced back on line immediately.[47] It should be noted, however, that MAIN's expected seasonal net export levels (for firm capacity, not economy transfers) range from 65 to 536 MW; both ECAR and SERC expect to export considerably higher levels (see table 7-6).[48]

Given the high percentage of nuclear plants presently under construction and considering the historical tendency for these types of plants to be more prone to delay than coal-fired units,[49] some MAIN utilities will be vulnerable to delays in completion of nuclear units. Such delays could substantially enhance the attractiveness of short lead time, modular technologies in the region.

Mid-Continent Area Power Pool (MAPP-U.S.)



MAPP-U.S.

The U.S. members of MAPP presently rely on coal and nuclear power for the bulk of their electricity generation—20 percent nuclear, 66 percent coal; hydroelectric power supplies 14 percent. MAPP is expected to continue its reliance on these technologies through the 1990s. While oil and gas accounted for less than 1 percent of total generation in 1984 and are expected to supply about the same in 1993, installed nuclear capability in the region is expected to exceed oil and gas by less than 2 percent during the same time period. so This makes oil and gas "swing fuels" in the region, with all the associated implications for avoided cost rates.

Demand growth is predicted to increase at an average annual rate of **2.4** percent over the next 10 years; utilities within the region are planning an 11.5 percent increase in capacity levels by 1993.[51] DOE projections of reserve margins (which assume scheduled completion of all units planned as of the end of 1983) indicate the region may fall below traditional reliability criteria in the late 1980s and early 1990s (see table 7-4). In addition, figure 7-3 suggests shortfalls of the 20 percent reserve margin under all but the lowest national demand growth case. Since construction has not yet begun on roughly 50 percent of the plants scheduled to come on line afier 1989,[5] system reliability concerns may create a window of opportunity for short lead-time technologies in the region.

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[46]Ibid.; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[47]Given projected shortfalls of some reliability criteria, this aim requires further explanation, which is found in the fact that MAIN's surplus is primarily confined to its offpeak (winter) season; shortfalls vis a vis the 5 percent adjusted reserve criterion are only expected in the summers of the years cited in table 7-4.

[48]MAIN utilities rely on intraregional transfers between MAIN subregions which have abundant coal and others which are either capacity deficient or oil and gas reliant (NERC, *14th Annual Review*, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983). If it finds itself in need of power (e.g., in 1984—see reserve margin section), imports can be gotten from MAPP and ECAR, and maybe also from SPP.

A recent study notes that MAIN's export capability to TVA (SERC) may be extremely low under anticipated 1988 peak conditions; export capability from MAIN to SPP and MAPP into MAIN under these projected conditions was judged inadequate (DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

[49]DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993* , op. cit., 1984.

[50]NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984; and NERC, *14th Annual Review*, op. cit., 1984.

[51]NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

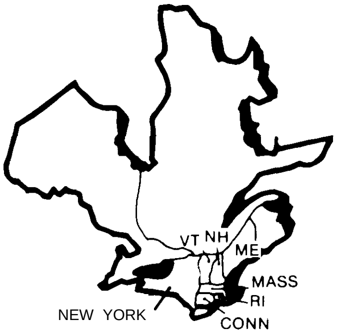
[52]NERC, *14th Annual Review*, op. cit., 1984.

MAPP members echo the concerns of other coal-reliant systems regarding the potential impact of more stringent air quality controls. Besides impeding overall reliability, increasing maintenance needs, and spurring "premature" plant retirements, they think retrofits could also lead to higher electricity costs for consumers. [53]

While MAPP's member utilities will not be increasing their reliance on nuclear power, storage of spent fuel from existing plants is a concern for the 1990s because onsite storage capacity will be fully used by that time. If national nuclear waste repositories for away-from-reactor storage are not available, some member systems expect they may have to reduce generation from their nuclear units.sq As in MAAC, this could create further need for new capacity.

The U.S. members of MAPP are summer peaking; its Canadian members are winter peaking. MAPP's U.S. members import power from its Canadian members, exchange power with neighboring council such as MAIN, and engage in a substantial amount of intraregional transfers available due to load diversity within the region. Studies are now underway regarding the feasibility of increasing the region's ability to import hydroelectric power from Manitoba into Minnesota and Wisconsin, and the Dakotas. [55]Given the usual economic attractiveness of such transactions, imports could emerge as a more cost-effective supply option than competing generating technologies if MAPP's import capabilities are increased.

Northeast Power Coordinating Council (N PCC-U.S.)



NPCC-U.S.

More than 50 percent of installed capacity in NPCC is oil-fired. Oil accounted for 38 percent of total generation in 1984; it is expected to account for 21 percent in 1993, Nuclear units accounted for 16 percent of 1984 capacity **and are expected to represent** 23 percent by 1993 (23 percent and 38 percent of total generation, respectively), while coal-fired units accounted for [11] percent of 1984 capacity and are expected to contribute 17 percent by 1993 (18 and 27 percent of generation, respectively). [56]

Decreasing the region's heavy dependence on oil hinges on completion of several new coal and nuclear units ranging in size from 800 to 1,150 MW. Some of these plants have proven quite controversial. For example, two of NPCC's nuclear units—Shoreham and Seabrook I—are among the most expensive plants in the country, with installed costs of $5,192 and $3,913 per kilowatt, respectively .57 increased electric rates associated with bringing these plants into the rate-base could run as much as 53 percent for Shoreham (Long Island Lighting Co.'s service area) and 63 percent for Seabrook I (for Public Service of New Hampshire's customers) .58 If demand growth continues as predicted (1.7 percent) and if some of these new plants are not completed and brought into service during the 1985-90 time period, the opportunities for new technologies will depend to a large extent on their competitiveness with new oil-fired, conventional units. (As discussed below, imports from Canada are not likely to be able to fill the resulting demand for power.) Given the high population density of many NPCC States, modular technologies which

[53]I bid.
[54]I bid.
[55]EIA, *Interutility Bulk Power Transactions,* op. cit., 1983; and NERC, *14th Annual Review,* op. cit., 1984.

[56]NERC, *Electric Power Supply and Demand, 1984-1993,* op. cit., 1984.
[57]Cook, op. cit., Feb. 11, 1985.
[58]Ibid.

are not land intensive might prove the easiest to site.

Cancellation of currently planned facilities could also adversely affect reliability criteria within the region. Given present plans to increase generating capability 14 percent over 1983 levels by 1993, it is expected that the systems within NPCC will meet traditional reliability measures into the 1990s. But problems are anticipated in mid-decade if these units are not brought on line, peak demand growth substantially increases beyond present forecasts, and/or presently operating nuclear units are not kept in operation,

On the other hand, if currently planned units come into service as scheduled, figure 7-3 suggests a shortfall of the 20 percent reserve margin in the early 199os only under the 4.5 percent national demand growth scenario.

NPCC systems import power primarily from the Canadian NPCC systems and ECAR. Reliance on oil makes economy transfers especially attractive to NPCC members, but the demand for such transfers exceeds existing, under construction, and planned transmission capacity both within the United States and between NPCC's U.S. and Canadian members. Present economy energy transfer levels leave little capacity for emergency flows; if emergency transfers are needed, economy transfers will be reduced. Even NPCCs coal burning utilities buy economy power when possible, since they have large loads and heavy peaks which must otherwise be met with oil-fired steam and peaking units.[59]

[59]EIA, *Interutility Bulk Power Transactions,* op. cit., 1983; NERC, *14th Annual Review,* op. cit., 1984; and DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993,* op. "cit., 1984.

Southeastern Electric Reliability Council (SERC)

SERC is characterized by a diverse fuel base which encourages heavy intraregional economy transfers as well as exchanges with interconnected systems in neighboring ECAR and SPP.[60] Regionwide, coal and nuclear plants accounted for 68 percent of 1984 installed capacity and 87 percent of total generation; 1993 projections call for continuation of these patterns,[61]

Twenty-two percent of the capacity in SERC is oil- or gas-fired. While these plants accounted for only **7** percent of total generation in 1984, this pattern varies markedly, with Florida's installed oil/gas capacity exceeding levels in the other SERC subregions by a factor of 5 or more.[62] Florida's reliance on oil and gas accounts for substantial intraregional economy transfers from other members of SERC, although transmission capacity constraints are limiting otherwise desirable transfers from hydroelectric and coal-fired generators in Alabama and Georgia.[63]

While Florida plans to decrease gas generation in 1993 to slightly less than 50 percent of 1984 levels, oil generation is expected to increase by 4 percent. The overall region is following a similar but less pronounced pattern; gas generation as a percent of total electricity generation is expected to decline by about 2 percent while oil generation increases about 1 percent.[64] Oil and gas costs and the availability of intraregional and

[60]EIA, *Interutility Bulk Power Transactions,* op. cit., 1983.

[61]NERC, *14th Annual Review,* op. cit., 1984.

[62]Sixty-seven percent of 1984 installed capacity and 35 percent of total generation in Florida was oil- or gas-fired; by 1993, this is projected to decrease to 57 percent of capacity and 31 percent of generation.

[63]NERC, 14th *Annual* Review, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions,* op. cit., 1983.

[64]NERC, *Electric Power Supply and Demand, 1984-1993,* op. cit., 1984,

interregional power will continue to be important factors affecting the relative economics of power supply alternatives in the region.

predicted average annual growth in summer peak demand varies between SERC subregions from 2.6 to 3.8 percent. Increased conservation and load management, changing demand patterns, increased construction costs, and the addition of customer generation are cited by the council as reasons for canceling or deferring construction on five nuclear plants and five coal units. Current construction plans call for a 22 percent increase over 1983 capacity levels by 1993. This includes 23 coal units (average size 588 MW), 9 nuclear units, 13 pumped storage facilities (average size 207 MW), and 19 hydro units (average size 40 MW).[65] If all of these units are completed on schedule, reserve margins in the area appear more than adequate through the early 1990s. As figure 7-3 illustrates, higher than expected demand growth (e. g., a national rate of 3.5 percent or more) could create potential capacity needs in the region and an opportunity for competitive new technologies. Assuming continued utility commitment to the plants now under construction, lower than expected growth could have the opposite elffect.

Southwest Power Pool (SPP)

SPP

Average annual peak demand growth predictions for SPP's three subregions for the 1985-93 planning period range from 1.1 to 6.1 percent. overall, the region's 1984 generating capability was predominately oil, gas, and coal, with oil and gas accounting for 55 percent and coal accounting for 38 percent of installed capacity. The 1993 projections show oil and gas capability reduced to 44 percent and coal increased to 41 percent. Installed nuclear capacity—3 percent of total capability in 1984—is expected to increase to 10 percent by 1993.[66]

SPP joins SERC as one of the only regions projecting an increase in reliance on oil for generation (from **4** percent in 1984 to 8 percent in 1993). Actual and projected fuel reliance for electricity generation in the region emphasizes coal, gas, and nuclear fuels, with coal increasing from 51 percent in 1984 to 53 percent in 1993; gas decreasing substantially, from 36 percent in 1984 to 23 percent in 1993; and nuclear doubling from 7 percent in 1984 to 14 percent in 1993.[67]

Fuel reliance within SPP is variable between subregions, encouraging intraregional transfers from coal-reliant areas to those emphasizing oil or gas. Both the Southeast and West Central subregions are heavily reliant on oil and gas, although both plan to decrease capability and generation from these fuels as a fraction of total capability and generation by the 1990s.[68]

Member utilities in SPP are planning to increase 1993 installed capacity by 21 percent over 1983 levels. As figure 7-3 shows, these plans leave reserves above the 20 percent margin through 1993 u rider all but the high national growth scenarios (i.e., 3.5 percent or more). The majority of these new plants are coal or lignite (1 0,200 MW), but more than half of them (about 6,000 MW) were only in the planning stage as of January 1984. The remaining new plants are nuclear (5,700 MW) and peaking capacity (1, 100 MW, mainly combustion turbines). if all of these plants are completed on schedule, the region will still be dependent on gas and oil (i.e., 44 percent of total planned capacity for 1993).[69] Delays could create potential opportunities for new technologies.

[65]NERC, *14th Annual Review*, op. cit., 1984.

[66]NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[67]Ibid.; and NERC, *14th Annual Review*, Op. cit., 1984.

[68]For example, 73 percent of 1984 generating capability in the Southeast subregion was oil- or gas-fired; *46* percent of total generation was from gas. In the West Central subregion, 51 percent of installed capability was oil or gas in 1984; 43 percent of total generation was from gas. By 1993, oil-gas capability as a percent of total plant is expected to decrease to 56 percent in the Southeast subregion and 42 percent in the West Central subregion, with generation from gas sources also decreasing. Dependence on oil generation, while small, is expected to increase in both subregions—from 11 to 17 percent in the Southeast, from 0,05 to 1.5 percent in the West Central. In contrast, the Northern subregion expects generation from gas to remain around 5 percent from 1984 through 1993, with oil generation less than 1 percent; installed oil and gas capacity was 29 percent in 1984 and is projected at 25 percent in 1993. From NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[69]NERC, *14th Annual Review*, op. cit., 1984.

As a hedge against possible oil and gas availability problems or price increases, member utilities are installing (or planning to install by the early 1990s) several new transmission lines to take better advantage of available economy power transfers from SERC, ERCOT, MAPP, and WSCC.[70] if new generating sources are needed, major factors affecting their comparative economics will include the price and availability of oil and gas, the regulatory climate affecting the region's coal plants, and the degree to which the promising cogeneration resource in Louisiana (see table 7-7) has been tapped.

Western Systems Coordinating Council (WSCC-u.s.)

Of ail the NERC regions, subregional differences in generation mix are most pronou need in WSCC, where there are four separate power pools–the Northwest Power Pool, The Rocky Mountain Power Area, the Arizona-New Mexico Power Area (ANMPA), and the California-Southern Nevada Power Area (CSNPA).

Members of the Northwest Power Pool Area (NWPP) primarily rely on hydropower; by 1993 they expect 62 percent of total generating capacity to be hydroelectric, 23 percent to be coal-fired, 9 percent to be nuclear, and less than 5 percent to be gas or oil. NWPP utilities expect growing capacity contributions from cogeneration and small renewables, especially small hydroelectric plants owned by third parties. According to a recent NERC report, NWPP members are concerned that using power from these sources will require increased utility operating reserves to offset "the unpredictability of the generation magnitude and the difficulty in monitoring the output since utilities have no authority regarding the dispatch of these resources."[71] (See chapter 3 for a discussion of these issues.)

The planning projections for 1993 made by members of the Rocky Mountain Power Area (RMPA) continue the present emphasis on coal and hydroelectric sources, with gas and oil power accounting for about 8 percent of installed generating capacity and nuclear accounting for less than 3 percent. The emphasis shifts away from hydropower in the WSCC's other subregions. For example, the ANMPA expects continued dependence on coal and oil-gas generation (respectively 51 percent and 28 percent of projected 1993 installed capacity), with nuclear expected to supply about 16 percent. CSNPA remains the most heavily dependent on oil and gas of all the WSCC subregions, which helps to explain that area's continued encouragement of unconventional technologies through various State and utility commission policies. CSNPA member systems expect 41 percent of total 1993 generating capacity to be oil and gas, 24 percent to be hydropower, 13 percent to be nuclear, 11 percent to be coal, 5 percent to be geothermal, 4 percent to be cogeneration, and about 2 percent to be from other sources.[72] Recent trends in development of cogenerated power to be sold to California utilities may substantially diminish the market for power from other third party producers in the near term.[73]

Due to both generation mix differences and load diversity, there are high levels of intraregional power transfers in WSCC, especially from regions rich in cheap hydroelectric or coal power to those relying on oil and gas. In particular, when water supply permits, oil- and gas-dependent California imports hydropower from the NWPP. Coal-burning States (Utah, Wyoming, and Arizona) sell power to the Pacific Northwest when water supplies there are low. The South-

[70] Ibid.; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[71] NERC, *14th Annual Review*, op. cit., 1984, p. 58.

[72] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984; and NERC, *14th Annual Review*, op. cit., 1984.

[73] For example, as of April 1985, Texaco and Chevron were each proposing to erect 1,200 MW of cogeneration capacity in the heavy oil fields in Kern County (total projected capacity of 1200 MW). Source: Burt Solomon, "Paradise Lost In California, " *The Energy Daily*, vol. 13, No. 80, Apr. 26, 1985.

western States in WSCC also import power from the Pacific Northwest when it is available. Construction plans are underway to improve transmission capability within WSCC itself as well as among it and SPP, MAPP, and MAAC to take better advantage of economy power transfers. ANMPA members are especially interested in maximizing use of available transmission facilities because they are capacity rich and financially dependent on selling surplus power to other WSCC members. Presently, there are insufficient facilities in place to take full advantage of available economy power transfers; in particular, transmission capability is insufficient to meet the demand for such transfers into the California-Southern Nevada subregion and for transfers between the Rocky Mountain and Arizona-New Mexico subregions.[74]

Predicted demand growth varies dramatically between WSCC subregions, with the predicted average annual increase in summer peak demand ranging from 1.9 percent (CSNPA) to 4.4 percent (ANMPA). If only 65 percent of the capacity presently planned to come on line in 1993 (41 percent coal and 34 percent nuclear) is actually built, member utilities expect that, while some reliability criteria may not be met, overall resources will be adequate as long as demand does not increase faster than currently projected.[75]

Alaska Systems Coordinating Council (ASCC)

Most of Alaska's population (i.e., 75 percent) resides in the "Rail belt" area stretching between Seward, Anchorage, and Fairbanks. Electricity in this region is provided primarily by indigenous natural gas, supplemented by coal, oil, and hydropower. The Railbelt is the only subregion interconnected by a common grid. If pending license applications with FERC for two hydropower projects are approved (Bradley Lake–90 MW, and Susitna–1 ,600 MW), ASCC expects the subregion will have sufficient capacity to meet expected demand past the year 2000.[76] It is doubtful that capacity credits for akernative technologies wou Id be available in the near term unrider this scenario; the Railbelt's projected 1985 peak is 717 MW; the 1990 peak is expected to be 918 MW.[77]

While the technical and environmental concerns surrounding the Susitna Project appear resolved, its size and cost are controversial. In response, the State is proposing to build the project in stages, starting with 500 MW and eventually upgrading the facility to 1,600 MW.[78] FERC is not expected to make a licensing decision until sometime in 1986.79

The ASCC expects greater development of the Railbelt's indigenous coal reserves if Susitna is not approved, creating a potential opportunity for new coal technologies. In addition, there are pending applications for waivers of the Fuel Use Act's natural gas generation prohibitions to allow Railbelt utilities to take greater advantage of the State's natural gas reserves.

Southeastern Alaska is served primarily by Federal and State hydropower projects. The rest of the State—consisting of widely dispersed villages (the "bush' ')-obtains electricity from diesel-fueled generators. Access to many of these areas is difficult. The bush subregion appears to offer the best development potential for dispersed electric generating technologies in Alaska. Of the technologies considered in this report, wind turbines appear among the likeliest candidates. There also has been some development of photovoltaics (PV) in remote areas, and hybrid systems linking wind or PV with battery storage may prove attractive. For any new technologies considered for electricity generation in the bush, project econom ics will be strongly influenced by the Power Cost Equalization Program.

Diesel fuel costs in the bush are high, resulting in electricity costs of up to $1 /kWh in some areas (e.g., where fuel has to be flown in). Electricity costs from 35 to 50 cents/kWh are typical. Under the Power Cost Equalization Program, these costs are subsidized by the State, so that

[74] NERC, *14th Annual Review,* op. cit., 1984; and EIA, *Interutility Bulk Power Transactions,* op. cit., 1983.

[75] NERC, *14th Annual Review,* op. cit., 1984.

[76] Information provided to OTA by the Alaska Systems Coordinating Cou ncil (ASCC), a N ERC affiliate, personal communication, May 1985.

[77] Ibid.

[78] I bid.

[79] Vic Reinemer, "Electrifying Alaska, " *Public Power,* November-December 1983, vol. 41, No. 6, pp. 10-19.

village residents pay only a small fraction (in some instances, less than 9 cents/kWh for the first 75o kWh used each month) of the production cost of electricity.BO The program is funded by royalties from oil sales.[81]

Outside of the comparative cost issues raised by present implementation of this cost equalization program, the main constraint on extensive wind development appears to be the absence of a grid allowing power transfers among villages and from dispersed sources to the State's major load centers. Obtaining third-party financing for small facilities could also be a problem, although the State has shown willingness to help facilitate new projects .82

Technical issues affecting wind development in the State include the substandard installation of many of the village diesel generator systems (e.g., systems with transmission lines running on the ground covered with wood boxes and/or generators housed in plywood structures susceptible to fire).[83] Gaining access to remote areas for construction and/or maintenance could also be a problem[84] for wind as well as any other technology.

The Alaska wind resource is especially attractive along the coast. The solar resource is strong but subject to extreme seasonal variation: in late winter, daylight is only available for 4 hours; in midsummer, light is available for about 20 hours. Geothermal resources are available on the Aleutian Islands, but there is no power transfer capability, either existing or planned, to transfer electricity from this area to the State's load centers, making substantial development of this resource for electricity generation unlikely.

Hawaii

The State of Hawaii is a chain of islands in the Hawaiian Archipelago. Most of the State's businesses and residents are on Oahu in or near Honolulu, the State capital. Oahu accounts for about 80 percent of Hawaii's peak electricity demand.

The State is served by a handful of investor-owned electric utilities relying almost exclusively on oil-fired capacity (99 percent of utility-owned generation in 1983 was oil-fired).[85] This generation is supplemented by seasonal purchases from third-party producers, most of which are sugar processing facilities cogenerating electricity from boilers fueled with bagasse, the pulpy residue from processing sugar.[86] Sugar is the State's main agricultural crop.[87] For approximately 48 weeks each year, firm power contracts from bagasse-fired cogeneration provide about 20 MW on the Big island (expected 1985 peak demand for the island: 99 MW), 20 MW on Maui (expected peak demand: about 102 MW), and 15 MW on Kauai (expected peak demand: 40 MW). Oahu, with an approximate peak demand of 949 MW, has no power from these sources. [88]

Power contributions from sugar processors are not expected to increase substantially over the next decade due to economic uncertainties in the industry. [89] Significant increases in power contributions from other biomass fuels are not expected. [90]

While the islands are too new geologically to have indigenous fossil fuels and there are no known offshore oil reserves nearby, Hawaii has abundant renewable and geothermal resources. A recent study predicts that, by 2005, indigenous

[80] For the first 750 kWh used each month, the State picks up any additional charge above 8.5 cents, and below 52 cents, per kWh. Source: Information provided to OTA by Kinetic Energy Systems, an energy firm in Anchorage, AK personal communication, May 1985.

[81] Information provided to OTA by Polarconsuh, an energy technology consulting firm in Anchorage, AK, personal communication, May 1985.

[82] Ibid.

[83] Ibid.

[84] Information provided to OTA by Independent Energy producers, a California-based alternative technology trade association, personal communication, May 1985.

[85] Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, 1984).

[86] Many sugar plantations also generate hydroelectric power, but this is used mainly onsite for irrigation.

[87] The sugar industry accounts for 80 percent of the jobs on the neighbor islands to Oahu. Source: *Hawaii Integrated Energy* Assessment (HIEA), vol. I, prepared for U.S. Department of Energy by the Department of Planning and Economic Development, State of Hawaii; and Lawrence Berkeley Laboratory, University of California at Berkeley, June 1981.

[88] These peak demand figures are estimates for 1985 provided to OTA by the Hawaiian Electric Power Co., Inc., in June 1985.

[89] Information provided to OTA by the Hawaiian Electric power Co., Inc., May 1985.

90 *HIEA*, Op. cit., 1981.

renewable resources could provide 90 percent of the island's electricity; each county has developed an energy plan aimed at decreasing dependence on imported fuels within cost and environmental constraints [91]

The State's solar resource is strong and consistent; the average insolation rate is higher than that of the mainland United States and there is also less seasonal variation. [92] Hawaii's wind resource is similarly promising; the northeast trade winds blowing across the islands offer one of the most consistent wind regimes in the world. Hawaiian Electric Renewable Systems, I nc.,[93] is installing fifteen 625-kW wind turbines on Oahu; these are scheduled to come on line by the end of 1985. There are also about 3 MW of wind capacity operating intermittently on the Big Island of Hawaii .94 The State may also be the site of a DOE demonstration project for a multi-megawatt wind turbine (MO D-5 B).

Most of Hawaii's energy resources are located far from the Oahu load center. High-temperature geothermal reserves are a case in point: the Puna resource on the Big Island of Hawaii is considered extensive enough to fulfill most of the State's power needs for decades to come.[95] However, presently there is no means of transferring power from the Big Island to oahu. This lack of transmission capability is the single biggest impediment to development of the islands' indigenous energy resources.

Development of an interconnected power transfer system hinges on successful design and installation of an undersea transmission cable capable of withstanding greater pressures, and extending greater distances, than has been attempted before. To date, submarine cables have not been installed below a depth of 1,800 feet and the longest distance a submerged cable has covered is 80 miles. A cable linking Hawaii with oahu would be submerged in a 150-mile wide, 7,000-foot deep channel (the Alenuihaha Channel). [96] One source estimates construction costs at anywhere between $250 and $600 million; this excludes the cost of research and development, which has been funded primarily by Federal sources.g[7] Whether or not the cable will ultimately prove feasible, or affordable, has not been demonstrated. The research phase is expected to be finished in the late 1980s.98

Hawaii's dependence on imported fuel provides a strong incentive to develop its energy resources.gg Solar, wind, and geothermal technologies are the most likely to be extensively developed; 100 batteries or fuel cells might offer some advantages but might be seen as undesirable if they continued the State's dependence on shipped-in fuels or materials. Switching to coal-fired technologies currently is unlikely given the land requirements for solid waste disposal, the resulting air quality impacts, and the lack of indigenous coal resources.

Load management is not a particularly attractive option for Hawaiian utilities since there is little incremental cost difference between their oil-fired generating units and there are no opportunities for off-peak, lower cost power purchases from neighboring facilities. System load factors have continued to improve since 1979, however, due to decreased electricity demand.[101] Load growth is expected to be minimal on Oahu; the

9.Ibid.

[92]JchnW.Sh u pe, "Energy Self-Sufficiency for Hawaii, " *Science*, vol. 216, June11,1982, pp. 1193-1199,

93A subsidiary of Hawaiian Electric Power Co. 's parent company, Hawaiian Electric Industries,

[94]Information Provided toOTA by Hawaiia n Electric Power CO., Inc., May 1985.

[95]*HIEA* (op. cit., 1981, *p.* 41) estimates the Puna resource at 100 to 3,000 MW centuries; other sources estimate it at 1,000 to 5,000 MW (information provided to OTA by Hawaiian Electric Power Co., Inc., May 1985).

[96]*HIEA*, op. cit., 1981.

[97]Information provided to OTA by the Hawaiian Electric Power Co., Inc., May 1985.

[98]Cable feasibi l ity studies are progressing; a tentative cable design has been selected, test protocol are being developed, and the requirements of handli ng l i ne installation and maintenance at sea are being studied.

[99]As of 1984, the State's average residential electricity rates were the highest in the United States (i.e., 11,4 cents/kWh based on 75o kWh): Energy Information Administration, *Typical Electric Bills, January 1, 1984* (Washington, DC: U.S. Department of Energy, December 1984), DOE/E IA-O040(84). Residential rates vary substantially between the islands; e.g., in 1982 electricity cost were 11.4 cents/kWh in Honolulu (Oahu), while rates on Molokai were more than 19 cents/kWh (Shupe, op. cit., 1982).

[100]Potential contributions from OTEC systems may be substantial in the long run, but the technical and economic issues associated with this technology make it an unlikely candidate for development in the 1990s,

[101]information provided to OTA by the Hawaiian Electric Power Co., Inc., May 1985.

neighboring islands may experience 2 to 5 percent annual growth, but this is from very small peak demand levels to begin with.[102]

The State's economy is heavily dependent on tourism and agriculture. Land values are at a premium, and Hawaii has strict zoning laws to protect its agricultural and recreational lands.[103] Development of the land-intensive solar and wind technologies to meet the State's electric power needs will definitely be affected by these factors. But the lack of transmission capacity between the islands poses the most immediate impediment to substantial development.

[102]Estimates provided to OTA by the Hawaiian Electric power Co., Inc., May, 1985.
[103]*HIEA*, op. cit., 1981

SUMMARY OF MAJOR REGIONAL ISSUES

Demand Uncertainty

Future electricity demand and the inherent uncertainty associated with estimating it are two of the most important factors affecting utility choices between electricity supply options. Predicted electricity demand growth rates differ dramatically within and among regions, and unanticipated changes in these predictions could substantially affect both overall system reliability and the need for new generating capacity. Traditional reliability measures such as generating reserve margins are very sensitive to demand predictions. This sensitivity is especially high in regions where substantial numbers of new coal and nuclear plants are under construction. In the long run, consumer reaction to the cumulative "rate shock" associated with bringing such large plants into the ratebase may increase utility commission actions encouraging greater reliance on alternative supply options.

The 1993 capacity levels in four NERC regions are expected to exceed 1983 levels by more than 20 percent; for three of these regions—ERCOT, MAIN, and SPP—this entails an increase of more than 75 percent in installed nuclear capacity. The oil-dependent NPCC region will be increasing its coal capability by similar percentages, although its overall capability increase over 1983 levels will be below 20 percent. If demand increases faster than predicted and construction delays occur, reserve margins in some of these regions may be adversely affected. If demand growth predictions have been overestimated, construction plans may have to be altered, with uncertain effects on the financial status of the utilities affected.

Present and Projected Fuel Reliance

Capacity needs and the relative attractiveness of available supply options are also strongly influenced by regional fuel and technology reliance, since these plant characteristics generally establish the benchmarks for technology cost comparisons. While most systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, reliance on premium fuels is expected to be strong enough in ERCOT, MAAC, NPCC, and some subregions of SERC, SPP, and WSCC that the economics of competing technologies will remain very sensitive to the price and availability of oil and gas.[104] This will apply even more strongly in the Florida subregion of SERC, the Southeast subregion of SPP, and the Arizona-New Mexico subregion of WSCC where, due to predictions of high demand growth and continued decreases in (or stabilization of) oil prices, reliability councils are forecasting increased dependence on oil. Regions characterized by heavy reliance on coal or nuclear power will be vulnerable to changes in present environmental regulations; the ultimate effect of regulatory changes will vary between utility systems and may create the need for additional power sources in some areas.

[104]These fuel reliance projections are from NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

Plant Life Extension

Over the next several decades, the age of existing generating facilities is likely to influence the need for new capacity because construction may be deferred if scheduled retirement of aging powerplants can be delayed by plant rehabilitation or efficiency improvements. Deferral prospects vary considerably by region, By 1995, approximately **40** percent of the fossil steam generating plants in MAIN, NPCC, and WSCC will be over 30 years old; many of these plants may be promising candidates for life extension. In terms of total installed capacity, the opportunities for life extension will be greatest in ECAR, SERC, SPP, and WSCC. In all regions, the degree to which this option is exercised will be heavily influenced by the comparative economics of other supply alternatives.

Other Key Variables

Opportunities for increased economy power transfers between and within regions are found to be attractive to a majority of utilities, but existing and planned transmission capacity will limit these transfers.

The potential for cogeneration tends to be State specific; opportunities are proving particularly strong in the Gulf States, e.g., Texas and Louisiana, and in California. These systems will often be in direct competition with the new technologies considered in this assessment.

Load management appears attractive in all regions, although peak reduction in oil-dependent systems could prove counterproductive in the long run if it defers replacement of costly peaking units.

Conservation is similarly attractive, although the resource is both difficult to define and tap completely.

Land and/or energy resource availability constraints are expected to limit development of geothermal, wind and solar technologies in some regions.

Utility economic and financial characteristics are so variable within as well as among regions that no clear regional generalizations are drawn.

Generalizations about regional regulatory characteristics prove similarly difficult, although the policies of some innovative utilities commissions are creating more favorable environments for new technologies than might otherwise be the case in their jurisdictions. In addition, given siting experiences to date, it seems reasonable to expect that developers of new technologies may experience permitting delays as localities adjust the regulatory process to accommodate new electric generating systems.

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