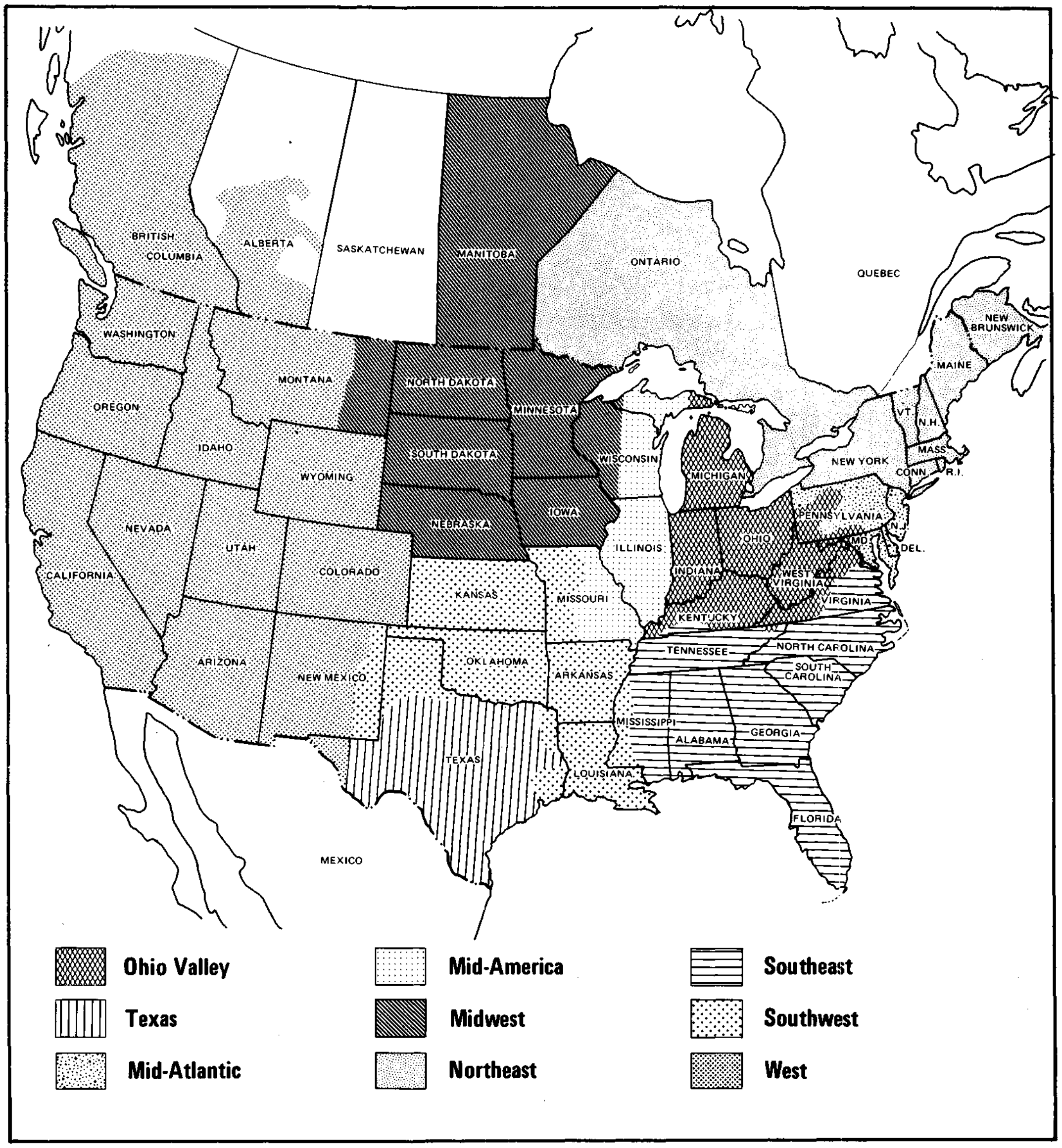
Figure 1.
National Electric Reliability Council



NOTE: The National Electric Reliability Council (NERC) was formed in 1968 to "augment the reliability and adequacy of bulk power supply in the electric utility systems of North America." It consists of nine Regional Reliability Councils and encompasses essentially all of the power systems of the United States as well as Canadian systems in Ontario, British Columbia, Manitoba, New Brunswick and Alberta.

TABLE 4. PERCENTAGE OF ELECTRICITY PRODUCED IN EACH NATIONAL ENERGY RELIABILITY COUNCIL (NERC) REGION, BY PRIMARY ENERGY INPUT, 1979

	Ohio Valley	Texas	Mid-Atlantic	Mid-America	Mid-west	North-east	South-east	South-west	West	Total U.S.
Nuclear	5.3	--	19.8	20.8	21.6	24.0	16.4	2.3	4.2	11.6
Coal	90.0	26.4	51.8	70.7	56.6	11.7	56.3	20.1	25.1	48.2
Oil	4.5	1.5	22.8	4.9	1.1	44.1	13.7	11.6	16.1	13.6
Gas	0.2	71.9	3.5	2.0	1.6	4.0	3.8	60.8	14.2	14.1
Hydro	0.9	0.2	3.9	1.4	14.6	17.8	10.3	1.0	40.4	12.7
Geothermal and Other	--	--	--	0.2	--	--	0.1	4.0	0.2	0.4
Pumping Energy[a]	(0.9)	--	(1.8)	--	--	(1.6)	(0.6)	0.2	(0.2)	(0.6)

SOURCE: Martin L. Baughman, The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments (H.R. 6930 and S. 2470), Southwest Energy Associates, Incorporated (April 1980).

a. Energy used to allow storage of electricity.

charges, which must be spread over as much generation as possible, and low fuel costs. For this reason, baseload plants are called upon first to meet load and operated at as high a capacity factor as possible.[1] Peaking units, the second type of generating capacity, are usually employed to meet daily or seasonal peak demands, for example during evening hours. Typically, these units are oil- or gas-fired turbines that have low capital costs and can be started up quickly. Because they are peaking units, their average capacity utilization rates are lower. Between baseload and peaking units is a midrange of plants that share some of the characteristics of both baseload and peaking units, often termed intermediate capacity.

Oil and gas remain attractive fuels for peaking purposes for two reasons. First, there are technical difficulties in making abrupt changes in load with coal- or nuclear-powered stations. Second, and perhaps more important, generating stations that burn oil or gas generally have low capital costs per kilowatt. Thus they can be used intermittently without imposing an unacceptable fixed-charge burden on the electricity they generate. Of course, pricing practices that reduce peak loads can result in the economic displacement of some oil and gas capacity, but the amount is likely to be small. More important, the bulk of oil and gas consumption occurs in generating units that service base and intermediate loads. Therefore, significant reductions in oil and gas consumption in the utility sector can only come through changes in the baseload fuel mix.

Recent history suggests a low rate of growth in nuclear baseload capacity in coming years. Thus, coal presumably will be the chief alternative in replacing oil and gas over the next decade. This implies that reducing utility oil and gas consumption will require either the reconversion of existing oil-fired, but coal-capable, units or the accelerated construction of new coal-fired units.

Many oil- and gas-fired units were converted from coal-fired units for environmental reasons before the runup in the price of oil. These units can be reconverted to coal. Other oil- and gas-fired units would have to be retired rather than reconverted. The economics of oil and gas replacement, therefore, involves a comparison of the costs of reconverting coal-capable oil- and gas-fired units and of accelerating construction of new coal-fired units to the costs of continuing to operate oil-fired units. The estimates that follow are based on two alternative assumptions: a continuation of

---

1. A plant's capacity factor is the ratio of the electric energy it actually produces to the maximum it theoretically could produce. For large baseload generating stations, it ranges from 55 to 65 percent.

current environmental policy on the one hand, and a stricter environmental scenario on the other.

Costs of Reconverting Existing Coal-Capable Units

It is estimated that approximately 21 billion watts (gigawatts) of oil-fired capacity once burned coal and could be reconverted back to coal. Half of this capacity is in New England, and an additional 21 percent is in the Mid-Atlantic states. Table 5 provides a regional assessment of the costs of reconversion under two different environmental scenarios. The first represents current environmental policy, meaning that some, but not all, units would require the installation of flue gas desulfurization equipment (FGD, or "scrubbers"). Under this standard, total conversion costs for 21 gigawatts of coal capacity are estimated at $5.77 billion in 1980 dollars. Regionally, conversion costs range from a low of $113 per kilowatt in the Southeast to $598 per kilowatt in the West. In New England and the Mid-Atlantic states, the costs range from $247 to $278 per kilowatt. Reconversion of the total 21 gigawatts of capacity would reduce utility oil and gas consumption by 350,000 to 400,000 barrels of oil equivalent per day.

A stricter environmental scenario would require the installation of FGD equipment on all converted units. This increases the estimate of total conversion costs to $9.5 billion, 65 percent higher than the first estimate. The application of FGD affects the regions differently, as seen in Table 5. In the Northeast, which has the greatest number of reconversions (11 gigawatts, or 52 percent of total national reconversions), estimated costs increase by only $95 per kilowatt, or 39 percent, to $342 per kilowatt. In the Mid-Atlantic region, however, costs increase from $278 per kilowatt to $663 per kilowatt--a 138 percent increase. The cost of reconversion in the Southeast remains the lowest under both scenarios. In the Ohio Valley region the requirement of FGD on all converted units raises the costs from $239 per kilowatt to $613 per kilowatt--a 256 percent increase. It should also be noted that the West currently requires FGD on all conversions (0.1 gigawatts), so that costs do not increase when more stringent environmental standards are applied. Generally, these costs increase to the extent that existing state air regulations are now lenient.

Fuel Cost Savings Compared with Reconversion Costs. Determining whether the capital costs of reconversion are offset by lower fuel costs requires assumptions about future oil, gas, and coal prices. Here it is assumed that oil and natural gas prices increase at an average rate of 4 percent per year faster than the rate of inflation from a base of $31 per barrel and $4 per million cubic feet in 1980, while coal prices rise 1 percent per year faster than inflation from a base of $36 per ton in 1980. These

TABLE 5. RECONVERSION COSTS OF COAL-CAPABLE GENERATING UNITS (All capacity to be converted by 1985)

Region	Capacity Converted (gigawatts) [a]	Costs Under Current Environmental Policy: Billions of 1980 Dollars	Costs Under Current Environmental Policy: Dollars per Kilowatt	Economic by 1985 [b]	Costs if Flue Gas Desulfurization Required: Billions of 1980 Dollars	Costs if Flue Gas Desulfurization Required: Dollars per Kilowatt	Economic by 1985 [b]
Ohio Valley	0.715	0.171	239	x	0.438	613	-
Texas	--	--	--		--	--	
Mid-Atlantic	4.482	1.246	278	x	2.973	663	-
Mid-America	1.599	0.560	350	-	0.820	513	-
Midwest	--	--	--		--	--	
Northeast	11.029	2.725	247	x	3.773	342	x
Southeast	1.909	0.215	113	x	0.597	313	x
Southwest	1.425	0.787	552	x	0.883	620	x
West	0.107	0.064	598	x	0.064	598	x
Total NERC	21.266	5.768	271		9.508	447	
Percent of Total Reconversions				93.3			68.0

SOURCE: Martin L. Baughman, The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments (H.R. 6930 and S. 2470), Southwest Energy Associates, Incorporated (April 1980).

a. These units were selected by the Department of Energy, after taking into consideration technical feasibility, environmental standards, cost-effectiveness, and other cite-specific limitations.

b. Indicated as x if the reconversion results in fuel savings greater or equal to capital costs by 1985, and as - if not.

assumptions are taken not to reflect short-term fuel prices, which are lower, but to represent price trends over the life of new generating equipment, which would extend into the next century. These estimates assume the decontrol of natural gas in 1985. A rate of return on equity of 16 percent and a real interest rate on debt of 3 percent were also assumed. Under current environmental policy, fuel cost savings offset the estimated capital cost of conversion in all regions except Mid-America (see Figure 1). Under the stricter environmental scenario, costs are lower in the Northeast (which accounts for over one-half of reconversions) and Southeast by 1985. In the Southwest and West, capital costs and fuel savings are approximately equal. Capital costs exceed fuel savings in the Mid-Atlantic, Mid-America, and Ohio Valley regions. By 1990, the Mid-Atlantic region enjoys cost savings of nearly 4 percent, the Ohio Valley region has costs that are unaffected by conversion, and the Mid-America region still experiences cost increases. By 1995, however, this region has cost decreases.

Nearly 70 percent of the reconversions (15.5 gigawatts) occur in the Northeast and Mid-Atlantic regions. In the Northeast region, which presently relies on oil for 44 percent of its primary energy input, 1985 variable fuel costs are reduced by 4.5 times the capital costs of reconversion on an annuitized basis (or three times the costs of reconversion under the stricter environmental rules). In the Mid-Atlantic region, fuel savings are also substantial, but under the stricter environmental regulations they do not offset higher capital expenditures until 1990. The Mid-Atlantic is representative of most of the regions in that reconversions are economic, but their payback periods can be lengthened by up to five years if additional environmental quality is required. Opting for less environmental protection (retaining the current standards required by states) allows for earlier rate reductions when compared to continued reliance on oil and gas, while opting for greater environmental protection (through mandatory FGD) postpones such rate reductions until the 1990s. This analysis has not attempted to estimate the benefits associated with additional environmental protection.

The Economics of Accelerated Retirements

Even if all available oil- and gas-fired plants that once burned coal were reconverted to that fuel, over 120 gigawatts of oil- and gas-fired capacity would remain, as shown in Table 6. Thus, the accelerated retirement of these oil- and gas-fired units and their replacement by coal-fired units must be considered in any long-term effort to reduce oil and gas consumption in the electric utility sector. As Table 6 shows, the Southwest and Texas regions represent the largest targeted area for accelerated retirement, one that is predominantly reliant on natural gas. Potential retirements in this area by 1985 total 57.8 gigawatts, or 47 percent of all

TABLE 6. POTENTIAL COAL RECONVERSIONS AND OIL/GAS CAPACITY REMAINING, BY REGION (In gigawatts)

	Mid-Atlantic	North-east	South-east	West	South-west	Texas	Total
Oil-fired Capacity	14.0	25.2	17.8	24.9	9.0	--	90.9
Gas-fired Capacity	--	--	0.1	1.1	21.3	28.9	51.4
Total	14.0	25.2	17.9	26.0	30.3	28.9	142.3
Reconversions	4.5	11.0	1.9	0.1	1.4	--	18.9
Remaining Oil and Gas Capacity	9.5	14.2	16.0	25.9	28.9	28.9	123.4

SOURCE: Martin L. Baughman, The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments (H.R. 6930 and S. 2470), Southwest Energy Associates, Incorporated (April 1980).

oil- and gas-fired capacity in the United States. Clearly the opportunity for accelerated retirement will be greatest here. The West, particularly California, is second in the number of potential retirements with 25.9 gigawatts. These three areas account for over two-thirds of possible accelerated retirements.

Table 7 compares the costs of operating an existing oil-fired plant with the costs of building and operating a new coal-fired plant. The comparison is made in five different areas having significant oil and gas capacity. Under current residual oil prices of $30 per barrel in 1980 dollars--the average price of residual oil purchased by utilities in the first six months of 1981 was approximately $34.00--and a real capital charge (in excess of inflation) of 10 percent, it is economic to construct a new coal-fired plant in Texas. The economic advantage of coal is marginal in Northern or Southern California and Northern Florida. The comparison is unfavorable for coal in the Northeast. If the real capital charge falls to 8 percent, because of lower interest rates or because the risks associated with

TABLE 7. COMPARISON OF THE OPERATING COSTS OF AN EXISTING OIL PLANT WITH THE ANNUALIZED COSTS OF A NEW COAL PLANT BY REGION AND UNDER ALTERNATIVE REAL CAPITAL CHARGE RATES (All figures in constant 1980 dollars)

	Existing Oil		New Coal Plant--By Region Texas		
	$30 per Barrel	$35 per Barrel	8 Percent	10 Percent	12 Percent
Capital Costs					
Initial Capital Cost (dollars per kilowatt)	--	--	1,285	1,285	1,285
Annualized Capital Cost (dollars per kilowatt)[a]	--	--	102.8	128.5	154.2
Annualized Capital Cost (mills per kilowatt-hour)[b]	--	--	18.1	22.6	27.1
Fuel Costs					
Average Fuel Cost (dollars per million Btus)	4.84	5.65	1.05	1.05	1.05
Heat Rate (Btus per kilowatt-hour)	9,340	9,340	11,048	11,048	11,048
Fuel Cost per Kilowatt-Hour (mills per kilowatt-hour)	45.2	52.8	11.6	11.6	11.6
Operation and Maintenance (mills per kilowatt-hour)	0.5	0.5	5.4	5.4	5.4
Total Cost (mills per kilowatt-hour)[c]	45.7	53.3	35.1	39.6	44.1

SOURCES: G. Martin Wagner, Substituting Coal Power Plants for Oil Plants, memorandum, United States Environmental Protection Agency (November 21, 1980); and the Congressional Budget Office.

a. Annualized capital costs in dollars per kilowatt are derived by multiplying the initial cost by the real capital charge rate.

TABLE 7. (Continued)

New Coal Plant--By Region											
Northern Florida			Northeast			Northern California			Southern California		
8 Percent	10 Percent	12 Percent	8 Percent	10 Percent	12 Percent	8 Percent	10 Percent	12 Percent	8 Percent	10 Percent	12 Percent
1,078	1,078	1,078	1,235	1,235	1,235	1,200	1,200	1,200	1,237	1,237	1,237
86.2	107.8	129.4	98.8	123.5	148.2	96	120	144	99.0	123.7	148.4
15.1	18.9	22.7	17.4	21.7	26.0	16.9	21.1	25.3	17.4	21.7	26.1
2.20	2.20	2.20	2.20	2.20	2.20	1.85	1.85	1.85	1.75	1.75	1.75
10,009	10,009	10,009	9,957	9,957	9,957	10,143	10,143	10,143	10,143	10,143	10,143
22.0	22.0	22.0	21.9	21.9	21.9	18.8	18.8	18.8	17.8	17.8	17.8
5.0	5.0	5.0	5.4	5.4	5.4	5.5	5.5	5.5	7.3	7.3	7.3
42.1	45.9	49.7	44.7	49.0	53.3	41.2	45.4	49.6	42.5	46.8	51.2

b. Annualized capital costs in mills per kilowatt-hour are derived by dividing costs in dollars per kilowatt by 5,694 (the total hours of generation per year assuming a capacity factor of 65 percent) and multiplying this quotient by 1,000.

c. Total costs vary directly with the interest rate. They are the sum of annualized capital cost, fuel cost, and operation and maintenance costs.

adding new capacity fall, then it becomes economic to build a new coal-fired plant in all the selected regions with oil prices at $30 per barrel. On the other hand, if interest rates continue to rise or the risks of adding new capacity persist unabated and the real capital charge rate increases to 12 percent, then only in Texas is it economic to construct a new coal-fired plant. Finally, if the price of oil increases at a real rate of 0.9 percent per year to $35 per barrel in 1990 (in 1980 dollars) then it becomes economic to construct a new coal-fired plant in all selected regions under all three capital charges.

Substituting Coal for Oil and Gas: How Much Is Enough?

The foregoing discussion has demonstrated that utilities could eliminate much oil and gas use by substituting coal, resulting in a cost saving if oil prices rise from current levels. Indeed, several utilities are already doing so by reconverting coal-capable units. But there is reason to believe that the rate at which substitution is proceeding is less than would be suggested by economic considerations alone.

Of course, a complete and instantaneous movement toward coal substitution should not be expected, and indeed is not suggested by purely economic considerations. As shown in Table 7, coal use may be marginally economic in some areas and uneconomic in others, depending upon the assumptions chosen. This is particularly true for retirements of existing oil and gas units that are not coal-capable. As Table 7 also shows, oil and gas unit retirements may be strongly influenced by capital charges. Thus, uncertainty over interest costs can lead management to delay coal conversion activities.

Relative fuel prices also influence the economic viability of switching to coal. As seen in Table 7, virtually all retirements of baseload oil and gas are economic when oil prices reach $35 per barrel (in 1980 dollars). At their current level, however, of $30 per barrel, this is not the case. The Department of Energy recently estimated the proportion of total oil and gas use that would remain economic at various fuel prices.[2] At $30 per barrel, 41 percent of oil and gas use by utilities was estimated to be cost-effective (much of this in peaking uses). At $40 per barrel, the proportion dropped to 23 percent. Similarly, a recent study by the Environmental Protection

---

2. U.S. Department of Energy, Reducing U.S. Oil Vulnerability: Energy Policy for the 1980s, prepared by the Assistant Secretary for Policy and Evaluation (November 10, 1980).

Agency examined the sensitivity of the utility fuel mix to coal prices.[3] Using a base case in which coal prices rose at a compounded rate of 2 percent in real terms annually from 1980 to 2020 (with annual increases declining from 5 percent in the early 1980s to 1.7 percent in the next century), coal was found to remain economic for electricity generation. A compounded rate of 3.5 percent (with annual increases of 5 percent throughout the 1980s and 3 percent thereafter) eliminated coal's cost advantage. Given the myriad of factors that influence delivered coal prices, including rail rates, severance taxes, and environmental costs, many utilities may hesitate to make strong commitments to coal.

Fuel prices, interest rates, and uncertainties in demand all stand as inhibiting factors in the movement toward coal substitution in utilities. Moreover, it should be noted that cost estimates involve "prototypical" plants, and thus might not apply to any particular situation. Some plants will have greater difficulty in switching to coal because of site-specific limitations such as proximity to populated areas, or land constraints that make coal storage or the installation of environmental equipment impractical.

Despite these caveats, there is reason to believe that the current rate of coal substitution is less than would obtain if economic considerations were to dominate fuel choice. This can be ascribed to the effects of several of the regulatory procedures described in Chapter II, particularly those that may serve to bias a utility away from making capital expenditures on new plants. Among these features are the use of AFUDC instead of immediate recoupment of construction work in progress, the use of fuel adjustment clauses allowing the automatic passthrough of higher oil and gas costs, and the determination of allowed rates of return that are lower than the cost of new capital. These regulatory procedures may slow the utility industry's conversion to coal; to the extent that they do so, the economy as a whole will bear the costs in lower efficiency. These costs are examined below.

INEFFICIENCY COSTS IN THE ELECTRIC UTILITY SECTOR

Inefficiency costs in the electric utility sector are borne by the economy as a whole, since more resources must be diverted to pay for

3. U.S. Environmental Protection Agency, "An Economic Evaluation of the Replacement of Oil-Fired Generation Capacity with Coal-Fired Capacity," prepared for the Energy Policy Division, Office of Planning and Evaluation, by Putnam, Hayes, and Bartlett, Incorporated, Cambridge (March 1981).

electricity than would otherwise be the case. These extra production costs depend on the levels of electricity supply and demand, particularly the former. Should new baseload generating capacity not keep pace with demand, utilities and their PUCs will be forced to call up retired units, use peaking and intermediate units at higher capacity factors, and wheel in excess power from adjacent regions. These sources of additional power are predominantly oil-and gas-fired, and hence tend to be uneconomic.

Inefficiency costs also pose a direct danger for electric utilities. As electricity prices rise to reflect these inefficiency costs, electricity consumption will certainly drop below levels that would have been obtained with a least-cost configuration. This demand effect may be sufficiently strong that utilities would be left with less revenue than they would have received had they expanded their capacity along least-cost lines. (In economic terms, the demand for electricity may be elastic.) This would lower utility profits and cash flow. Some utilities might then be forced to seek still higher rates to recoup their losses, perpetuating the downward spiral of sales. Moreover, as utility cash flow, sales, and profits decreased, both the impetus and ability to make new cost-saving investments would decrease, exacerbating the problem further. Thus, inefficiency costs may trigger a downward spiral of electricity sales and lead to even larger economic losses.

Costs of Incorrect Fuel Choice

Table 8 presents estimates of utility oil and gas consumption by electric utilities in the year 1990; these projections provide a basis for estimating the inefficiency costs associated with inappropriate oil and gas consumption. They reflect the assumption that 196 gigawatts of capacity are added between 1981 and 1990.

As seen in Table 8, utility oil and gas consumption is projected to be 1.9 million barrels per day in 1990. Not all of it, however, would be used for baseload generation. The proportion of oil and natural gas used for baseload generation has declined steadily throughout the 1970s. Assuming that 40 percent of both oil and gas would still be used for baseload generation in 1990, uneconomic oil and gas use would result in excess annual electricity costs of $1.5 billion in 1980 dollars, or $2.1 billion in 1990 dollars.

Costs of Inadequate Capacity

Tables 8 and 9 provide a basis for comparing the inefficiency costs of using excess oil and gas for electricity production in the year 1990. Table 8

TABLE 8. PROJECTIONS OF DEMAND AND CAPACITY GROWTH OF OIL AND GAS CONSUMPTION IN THE ELECTRIC UTILITY INDUSTRY, 1981-1990

	Average Annual Demand Growth, 1981-1990 (percent)	Capacity Additions, 1981-1990 (gigawatts)	Reserve Margin (percent)	1990 Oil and Gas Consumption (thousands of barrels per day)
Texas	4.6	55.98	18	403
Gulf States	3.7	35.35	27	202
Missouri/Kansas	3.8	15.70	24	17
Oklahoma	4.0	22.14	20	98
California/Nevada	2.7	58.74	16	314
Florida	3.8	30.54	15	249
New England	2.8	26.29	28	109
Mid-Atlantic	2.8	52.31	29	116
New York	1.3	32.59	37	147
Virginia/Carolinas	3.8	51.09	26	19
Arizona/New Mexico	5.8	19.92	42	18
Ohio Valley	3.6	119.3	33	54
Mid-America	3.2	54.33	24	29
TVA/Southern	3.1	76.01	38	24
Rocky Mountain	5.9	10.95	28	5
Northwest	4.5	58.10	40	94
Midwest	4.2	33.44	24	27
Total United States	3.5	200.49	30	1,918

SOURCE: Los Alamos National Laboratory, Electric Utility Oil and Gas Use in the Eighties, LA-9319-MS (April 1982).

presents a base case, under which oil and gas consumption is projected as the combined equivalent of 1.9 million barrels per day. Table 9 presents an estimate of oil and gas consumption under a case in which new-capacity additions drop by one-third below those in Table 8 and in which oil and gas consumption rise to the equivalent of 3.2 million barrels per day. Thus, a 33 percent reduction in new capacity translates into a 67 percent increase in oil and gas burning by utilities. If real oil prices remain at $30 per barrel in this decade, excess electricity production costs would be $3.0 billion in 1980

TABLE 9. POTENTIAL INEFFICIENCY COSTS IN 1990 UNDER A REDUCED RATE OF NEW CAPACITY

	Reduction in Capacity (gigawatts)	Reserve Margin (percent)	Oil and Gas Consumption (thousands of barrels per day)	Increase in Oil and Gas Consumption Over Base Case (thousands of barrels per day)	Estimated Excess Production Costs (oil price at $30 per barrel, in millions of 1980 dollars)	Estimated Excess Production Costs (oil price at $35 per barrel, in millions of 1980 dollars)
Texas	6.59	15	594	191	649.3	988.0
Gulf States	5.29	21	351	149	503.7	767.6
Missouri/Kansas	1.93	15	23	6	11.5	22.1
Oklahoma	2.60	16	170	72	137.2	264.7
California/Nevada	10.00	15	608	294	564.2	1,085.0
Florida	3.73	15	358	109	209.2	402.3
New England	3.44	21	195	86	118.4	227..7
Mid-Atlantic	1.74	27	149	33	45.4	87.4
New York	1.71	30	197	50	68.8	132.2
Virginia/Carolinas	2.80	24	34	15	28.8	55.4
Arizona/New Mexico	1.98	28	30	12	22.0	42.4
Ohio Valley	6.87	28	87	14	26.9	51.7
Mid-America	2.80	19	37	8	15.4	48.1
TVA/Southern	.68	37	24	0	0	0
Rocky Mountain	2.68	15	67	62	186.7	359.1
Northwest	6.55	36	212	118	355.3	683.4
Midwest	4.77	15	61	34	65.2	125.4
Total United States	66.18	18	3,197	1,279	3,008.0	5,322.2

SOURCE: Los Alamos National Laboratory, Electric Utility Oil and Gas Use in the Eighties, LA-9319-MS (April 1982); and Congressional Budget Office.

dollars. Should oil prices rise to $35 per barrel, the costs would increase to $5.3 billion. Both estimates, it should be noted, are for the year 1990 only.

Analyzing the low-supply case geographically, the bulk of the increased oil and gas consumption (1.0 out of the 1.3 million barrels per day increase) would be attributable to the current seven largest oil and gas consuming areas. The largest increase would occur in the Texas, California/Nevada, Gulf States, and Oklahoma regions.

The inefficiency costs are based on the estimated differential between using oil and gas on one hand or coal on the other hand in baseload generation. Areas that incur inefficiency costs do so through the uneconomic baseload use of oil and gas. For the purposes of these estimates, the average real cost of coal-fired power is 42 mills per kilowatt hour, while oil-fired units cost 51.3 mills per kilowatt hour assuming a capacity factor of 65 percent, a heat rate of 10,500 Btus per kilowatt-hour, and oil prices of $30 per barrel in 1980 dollars (or approximately $54 per barrel in 1990 dollars). In addition, uneconomic production can occur if supply reductions endanger reliability levels so that oil or gas peaking units must be constructed or called up. The cost differential between peaking oil- and gas-fired units and coal or nuclear baseload costs is even greater than the difference between coal-fired and oil- or gas-fired baseload costs. The model used to make these estimates assumed that regional reserve margins would not drop below 15 percent (implying the construction of peakers to maintain this reliability level.)[4] This margin is found in five of the seven most oil- and gas-reliant regions (the New England and New York regions have considerable reserve margins in both cases), where the bulk of oil and gas is still used for baseload and intermediate purposes.

These estimates of excess production costs are conservative, for three reasons. First, they do not include the production inefficiencies accompanying oil and gas consumption in the base case. Since utilities are financially constrained on the whole, many have planned capacity additions that merely meet anticipated load growth and do not accelerate the retirement of existing oil and gas units. In some cases, analysts suspect that the load growth figures may even be purposefully underprojected so that the utilities will not be forced to construct new plants. In any event, a rough estimate of uneconomic oil and gas use can be made for the base case. In relation to total oil consumption in electricity production, baseload oil consumption declined from around 65 percent in 1973 to 44 percent in 1978, while baseload gas consumption remained relatively stable at approximately 60

---

4. Los Alamos National Laboratory, Electric Utility Oil and Gas Use in the Eighties (April 1982), p. III-18.

percent. Intermediate and baseload consumption combined accounted for roughly 85 percent of all oil and gas consumption in 1978. It may be assumed that baseload oil use will continue to decline, while natural gas will continue to be used primarily in baseload. Thus, even if only 40 percent of the total projected 1.9 million barrels per day of oil and gas use in 1990 under the NERC base case occurs in baseload use, this implies excess electricity production costs in 1990 of nearly $1.5 billion in 1980 dollars, or $2.1 billion in 1990 dollars.

Second, the low-supply case may not be low enough. It assumes that all the units currently under construction are completed on schedule. In the months after the NERC study was issued, a number of coal and nuclear units were cancelled or deferred indefinitely. Among them were plants under construction that the study had assumed would be completed for its low-supply case. These cancellations and deferrals (in conjunction with potential additional cancellations throughout this decade), especially in areas where reserve margins are low, imply additional uneconomic oil and gas use in baseload, intermediate, and peaking modes, and a decline in reliability reserve margins.

Finally, these excess production cost figures assume that oil prices rise only with inflation, which was not the case during the 1970s. If oil prices were to rise in real terms to $35 per barrel in 1990 ($62.65 in 1990 dollars), excess production costs (as shown in column 6 of Table 9) could total $5.3 billion (or $9.4 billion in 1990 dollars, assuming the same inflation rate).

Moreover, these excess production cost figures cover only one year, 1990. Inefficiencies would mount over the decade under the low-supply scenario in which new capacity additions drop by a third. The Los Alamos study has provided an estimate of cumulative losses over the entire decade. It is based, however, on rapid rises in oil and gas prices, and therefore, is most likely an overestimate.[5]

---

5. Ibid. Over $33 billion extra in revenue is required under the low-supply case, with the greatest losses in the most oil- and gas-reliant areas. These losses amount to over $9 billion in California, $4.5 billion in Texas, over $4 billion in the Gulf States region, $3.4 billion in Florida, and $1.7 billion in both New England and New York State. The Northwest losses total $4.7 billion, while the Rocky Mountain region loses $1.6 billion. It should be noted that more coal-reliant areas (like the Mid-America and Mid-Continent regions) actually require less revenue under a reduced-supply case in that they would (Continued)

Effects Beyond 1990

If delays in adding new capacity continued beyond 1990, they would extend the uneconomic use of oil and gas and further reduce reserve margins. A recent study estimated the effects of such constraints if continued through 1995.[6] If coal-fired and nuclear capacity additions were limited to 108 gigawatts and 76 gigawatts respectively through 1995, oil and gas use would increase from a projected 0.6 million barrels per day in 1995 to over 2.9 million barrels per day. In other words, a 40 percent reduction in capacity additions (from 309 gigawatts to 184 gigawatts through 1995) would cause nearly a 400 percent increase in oil and gas use. Reserve margins would also decline from a national average of 45 percent under the base case in 1995 (where demand grows at an annual rate of 3.2 percent) to 25 percent. These averages mask regional variations, of course. The Northeast and Mid-Atlantic states would maintain more than adequate reliability levels, while the West would be required to construct oil-and gas-fired peaking units to maintain reliability. Again, the increased oil and gas use would occur primarily in base load in areas that are currently the most oil- and gas-reliant. Rates would increase the most in the California-Nevada-Arizona region (24.2 percent), followed by the Texas-Gulf States region (18.3 percent), New York (6.0 percent), and the Southeast (5.5 percent).

REGULATION AND UTILITY CAPITAL COSTS

An additional unnecessary cost burden involves the capital costs of utilities. Traditionally viewed as low-risk endeavors, utilities have lately been seen as riskier. Since 1973, Moody's has announced 79 lowered debt ratings for electric utilities and only 12 increases. Where utilities at the beginning of the 1970s were generally considered AAA credit risks, many

---

5. (Continued)
not need all of the capacity now planned. Yet these savings are small in relation to the losses experienced elsewhere. The Los Alamos projections assume, however, that oil and gas prices rise at an annual rate of over 4.5 percent over the decade, so that oil prices reach \$44 per barrel (in 1980 dollars) and gas prices the equivalent of over \$43 per barrel by 1990. While assuming that a \$30 per barrel figure to derive the initial excess production cost estimate may underestimate future oil prices, a \$44 per barrel figure (or approximately \$79 per barrel in 1990 dollars) appears excessive.

6. U.S. Department of Energy, Impacts of Financial Constraints on the Electric Utility Industry, DOE/EIA-0311 (December 1981).

are now two or three grades lower at A or BAA. Companies with lower credit ratings must pay higher interest rates to borrow. In early 1982, an A-rated electric utility had to pay about 100 basis points (one percentage point) more to borrow in the intermediate- and long-term bond markets than an AAA-rated utility. A borrower rated BAA had to pay 175 basis points, or 1.75 percentage points, more. This deterioration in utility bond ratings adds to the already existing burden of high interest rates.

Credit ratings are affected by regulatory behavior. It has been shown that utilities subject to regulation by PUCs classified as "favorable" benefit from equity capital (stock) costs that are nearly two percentage points less than for utilities operating in states where regulatory policy is regarded as "unfavorable."[7] The same holds for bond yields.[8]

The slowness of PUCs to grant rate relief is not the only way in which regulation affects the cost of financing utility investment. Another is the increased sensitivity of regulators to the environmental costs and risks associated with coal-fired and nuclear plants, which has lengthened the time required to plan, site, and construct a generating facility from an average of four or five years in the 1960s to about twelve years today. Longer construction periods, and the general unwillingness of PUCs to include CWIP in the rate base, require the utilities to borrow more per dollar of construction.

The regulatory procedures that determine whether the environment within which a utility operates is "favorable" are precisely those discussed earlier in this chapter. As has been seen, the substitution of AFUDC for CWIP has lowered the quality of utility earnings, and makes a utility vulnerable to future decisions by its PUC that may jeopardize its ability to recoup its AFUDC account. Regulatory lag has lowered utility earnings from the levels they were initially allowed. The use of historical test periods for measuring operating costs has biased utility earnings downward in an inflationary environment. The use of fuel adjustment clauses may have blunted utilities' incentives to replace outmoded capital equipment with newer generating stock. Oil and gas costs can be passed along automatically under fuel adjustment clauses, while capital expenditures to

---

7. Robert R. Trout, "The Regulatory Factor and Electric Utility Common Stock Investment Values," <u>Public Utilities Fortnightly</u> (November 22, 1979).

8. S.H. Archer and G.H. Atkinson, "The Cost of Capital and State Regulation of Electric Utility Rates," Center for Business-Government Studies, Center Paper 79-7 (July 1979).