market is invoked, in which the wage rate is fixed and labor supply adjusts to possibly less than a full-employment equilibrium. In addition, other components of the flow-of-funds account, such as the current account balance and government deficit, are considered in conjunction with the above for policy analysis purposes.

The core of the base year equilibrium data set of the model in this study is a SAM of the U.S. economy for 1987, constructed by Hanson and Robinson (1987). This data set contains both *make* and *use* versions of the U.S. Input-Output Table to capture the production and utilization of commodities. The SAM, in addition to providing the basic data set for model calibration, also provides initial values for endogenous variables and levels for exogenous variables. In this study, a 20-sector version of the model is used, including five mining sectors and two energy utility sectors (see Appendix 4E).

Some key parameters of the empirical model—Allen elasticities of substitution between aggregate inputs—are presented in Table 4.4.1. They represent a synthesis of estimates available in the literature. Sensitivity tests were performed on these values.

Table 4.4.1 Allen Elasticities of Substitution for Selected Sectors

Sector	σ_{KE}	σ_{KL}	σ_{KM}	σ_{LE}	σ_{LM}	σ_{EM}
Construction	.70	.20	.55	-.25	.89	.77
Petroleum Refining	.25	.90	.35	.20	.50	.05
Manufacturing	.70	.20	.55	-.25	.89	.77
Transportation	.70	.90	.35	.25	.10	.05
Utilities	.70	.90	.02	-.10	.01	.01

[a]The symmetry properties of our production function require $\sigma_{ij} = \sigma_{ji}$.

4.4.4 Simulation Results

In this section, simulation results are presented for both autonomous and price-induced conservation strategies to be implemented in the Year 2000. The first set of simulations represents best estimates of the effects of these responses on major economic indicators for the economy in general and the energy sectors in particular. Other simulations examine the sensitivity of the results to key parameters and behavioral considerations.

Energy policy responses are simulated in two ways. First, to analyze *autonomous* conservation, or the *mandated* response to a command-and-control policy, the energy use parameters were reduced in the model by 12.8% across-the-board (recall the U.S. response to a global policy regime discussed above). The model then analyzes sectoral (partial equilibrium) and multi-sectoral (general equilibrium) responses. Also, sensitivity tests were performed to ascertain the possible offsetting effects of energy-saving equipment needed to implement the policy goal. Note that in actuality, abatement cost curves will vary across sectors and the least-cost no regrets level will thus vary. Due to the lack of data on sectoral conservation potential, a uniform level was simulated. Given the fact that command and control policies are typically applied across the board, this exercise may not in fact represent too much of a departure from reality.

The direct application of a carbon tax or permit trading to examine *price- induced* conservation is simulated. This is modeled as a price increase in primary energy (tax on fossil fuel production), as indicated in Table 4.4.2. Note that in this case the optimal response calls forth differential reductions in energy use and differential levels of interfuel substitution across sectors.

Note that, in effect, the optimal response to CO_2 mitigation policies is likely to be a combination of autonomous conservation and various types of substitution, which have been separated to isolate unique features of each. The overall outcome will thus be some weighted average of the two strategies. Referring to Figure 4.4.1, the exact combinations would be determined by the intersection of the carbon tax level (or equilibrium permit price) and the marginal cost of abatement.

4.4.4.1 Basic Results

The prime simulations are presented in Table 4.4.3 in terms of their impacts on five major economic indicators. The basic conservation case (line 1 of Table 4.4.3) is estimated to yield an overall decrease in GNP of 1.44% and a reduction in employment of 2.05%. Economywide investment decreases by 4.41%, with exports actually increasing by 2.75% and imports declining by 3.63%. The difference in the GNP and Employment results indicates that there is proportionally greater substitution away from labor-intensive goods

Table 4.4.2 Transformation of a Carbon Tax to an Ad Valorem Tax

	Fuel		
	Coal (ton)	Oil (bbl)	Gas (tcf)
Heat Content (million Btu per unit)	21.94	5.80	1.03
Emission Rate (kg per million Btu)	26.90	21.40	14.50
Conversion Factor (tons per unit)	0.59	0.12	0.02
Carbon Tax (1990 $ per unit carbon)	38.35	38.35	38.35
Ad Valorem Tax (1990 $ per physical unit)	22.63	4.76	0.57
Fuel Price, Year 2000 (1990 $ per physical unit)	26.64	26.40	2.72
Price Increase (percentage change)	85.12	18.02	20.83

Specifically, the following four cases were simulated:

1. Simple conservation—a 12.8% cutback in purchases of all fossil fuel energy, including utilities, in all intermediate and final demand sectors;
2. Conservation, but with the entire cost-savings in each sector being assigned to increased purchases of energy-saving equipment;
3. Price-induced substitution, but with the carbon tax being imposed only on domestic use of domestically produced primary energy; and
4. Price-induced substitution, but with the carbon tax being imposed on domestic use of both domestic and imported primary energy.

than is the case for other inputs. Note also that the impact of this case (and all others) in terms of a welfare measure such as compensating variation, are also negative, though by a smaller percentage than the macro indicators.

Aggregate energy use declines as do CO_2 emissions, but startlingly less than expected. As expected, coal and electric utilities suffer the largest declines. Even though direct effects are

Table 4.4.3 Economywide Impacts of CO_2 Mitigation, Year 2000: Base Cases (percentage change from baseline)

Case	Real GNP	Employment	Investment	Exports	Imports	Welfare[a]	Energy Use	CO_2 Emissions
1. Conservation (100% cost-saving)	-1.44	-2.05	-4.41	2.75	-3.63	-0.84	-3.32	-3.44
2. Conservation (100% equipment offset)	-3.65	-3.94	-4.11	0.84	-3.02	-2.25	-9.16	-8.96
3. Interfuel Substitution (no tax on imported oil)	-1.56	-2.02	-3.59	-1.79	-1.93	-1.39	-24.17	-26.07
4. Interfuel Substitution (tax on all oil)	-1.77	-2.28	-3.37	-2.60	-3.38	-1.64	-25.49	-27.22

[a]As measured by compensating variation.

proportional, general equilibrium effects allow for substitution away from these sectors. At first one would expect declines of greater than 12.8% in each energy sector given the direct response and subsequent multiplier effects. However, it appears that the price decrease for each fuel causes energy to be more attractive to the point where there is a significantly offsetting substitution effect toward it. This has been pointed out in a number of studies that warn of the unintended side-effects of autonomous or mandated conservation (Khazzoom, 1980). Other general equilibrium effects are operative as well but are too difficult to sort out without further experimentation (see below). Overall, the downside effects are not overcome by stimuli from increased purchasing power, international competitiveness, or multiplier effects. The results for the energy sectors are presented in Table 4.4.4.

Table 4.4.4 Energy Sector Impacts of the Conservation (100% Savings) Response, Year 2000: Base Case (percentage change from baseline)

Energy Type	Gross Output	Employment	Exports	Imports
Coal	-3.85	-4.64	0.39	-6.52
Oil/Gas Extraction	-1.03	-2.75	4.36	-4.43
Petroleum Refining	-2.28	-2.84	2.61	-5.16
Electric Utility	-4.21	-5.36	1.99	-7.18
Gas Utility	-2.49	-3.07	3.37	-5.33

Note the irony of this policy response. In effect, the initial willingness of industry to decrease energy consumption by 12.8% results in offsetting factors that would not enable the U.S. to meet its CO_2 reduction target. That is, the overall average decline of energy use of 3.32% would mean that CO_2 emission reductions would only be one-fourth of those intended. This is somewhat disconcerting and indicates that energy users on the average might need to undertake several times the amount of initial energy conservation to yield the intended overall 12.8% reduction.

The results of a modified conservation response is presented in Case 2 of Table 4.4.3. When the entire cost savings is offset by increased costs of energy-saving equipment, the negative impacts are even greater than in the base case. Table 4.4.3 shows that GNP declines by 3.65% and employment by 3.94%. The key to understanding this decline is the simultaneous reduction in economywide investment. It would appear that the *crowding-out* effect of investment in energy-conserving equipment is substantial and has a dampening effect on the economy (see also Jorgenson and Wilcoxen, 1993). However, there is some bias in the model and its application. The investment equations are specified for more general cases. The model thus views the earmarking of investment funds for energy conservation as sub-optimal (as do the vast majority of the models in the literature). On the other hand, if the rate of return on this investment specifically reflected the gains that could be brought about, it might very well be that energy-saving equipment would be one of the better uses of investment funds. The otherwise expansionary effect of this increased investment might cause overall investment and output declines to be lower than Case 1. To be positive overall, however, would require considerable impetus. The 12.8% decrease in energy costs in most sectors translates into a 0.1 to 1.0% cost savings in each sector. This presents a relatively minor advantage to investment in energy-saving equipment over other alternatives.

The effect of Case 2 on individual energy sectors is presented in Table 4.4.5. The reductions come close to the 12.8% due in great part to investment considerations, which represent a type of forced substitution of capital for energy, in addition to other responses. Whereas in Case 1, energy intensity declines were below 0.2% for all sectors, here several sectors wind up with declines of greater than 2.0%.

In Cases 3 and 4 (Table 4.4.3), the response to a carbon tax or permit trading in terms of direct inter-fossil fuel substitution (IFFS) and other factor substitution (OFS) is simulated. In Cases 3 and 4, the increased cost of the energy aggregate leads to substitution between it and other aggregate input categories. These responses are further affected by various other general equilibrium interactions that take place, including product mix substitution (PMS). In Case 3, the tax applies only to domestic use of energy produced in the U.S., while in Case 4 it applies to imported energy (primarily oil) as well.

Case 3 also yields a negative impact on the economy in terms of GNP and employment. The economic impacts of this case are quantitatively and qualitatively similar to Cases 1 and 2,

Table 4.4.5 Energy Sector Impacts of the Conservation (100% Equipment Offset) Response, Year 2000: Base Case (percentage change from baseline)

Energy Type	Gross Output	Employment	Exports	Imports
Coal	-8.05	-9.12	-13.01	-4.73
Oil/Gas Extraction	-9.63	-12.07	-1.34	-13.66
Petroleum Refining	-11.35	-12.10	-34.42	3.47
Electric Utility	-6.92	-9.30	-12.06	-4.24
Gas Utility	-10.05	-11.32	-30.66	2.48

except that exports decrease. The negative impacts on the economy are more pronounced in Case 4 because more inputs (i.e., imported oil) suffer price increases. These impacts are not offset by relatively more favorable terms of trade in Case 4 versus Case 3.

The effect of Case 3 on individual fuels is presented in Table 4.4.6. As would be expected from Table 4.4.2, coal bears the brunt of the carbon tax, as reflected in a reduction in the sector's gross output of over 44%. Domestic crude oil production declines by 6.77% and imports decline by 8.77%. Sectoral results for Case 4 are very similar to Case 3, except that crude oil import reductions are much greater in the latter.

Perhaps the major differences between the mandated and incentive-based conservation responses are the energy and CO_2 reductions. In Case 3 (Table 4.4.2) aggregate energy use decreased by 24.17% and total CO_2 emissions decreased by 26.07% (both figures are slightly higher for Case 4). The nearly 2.0% differential between energy use and CO_2 emission reduction reflects a significant amount of fuel switching. The majority of the emission reduction, however, stems from a relatively much greater decrease in energy use in Cases 3/4 vs. Cases 1/2 (compare also Tables 4.4.4 to 4.4.6). Some energy intensive sectors are the hardest hit by the general equilibrium effects, e.g., steel, stone (cement), and transportation.

Table 4.4.6 Energy Sector Impacts of the Interfuel Substitution Response to Tax on Domestically Produced Energy, Year 2000: Base Case (percentage change from baseline)

Energy Type	Gross Output	Employment	Exports	Imports
Coal	-44.37	-37.43	-65.44	-19.31
Oil/Gas Extraction	-6.77	-8.76	-3.35	-8.77
Petroleum Refining	-7.72	-6.39	-32.05	8.74
Electric Utility	-7.85	-10.11	-34.49	9.32
Gas Utility	-1.69	-2.90	-18.94	8.34

Apparently declines in the energy sectors do contribute to the overall negative effect on the economy in the various simulations, but there are some offsetting effects in the carbon tax/permits cases, since decreases in GNP are only slightly higher despite a 7-8 fold decrease in energy production vis-a-vis Case 1. The relatively greater labor intensity of non-energy industries is one part of the explanation (compare the economywide employment decreases between Cases 1 and 3). Other explanations include the relatively lower negative impact on investment and the spending impetus of carbon tax revenues (though only to a slight degree as will be shown below).

4.4.4.2 Sensitivity Analysis

It is acknowledged that the CGE model is based on a calibration method with less than ideal statistical properties, and that several facile assumptions have been invoked. Therefore, it is not unreasonable to question the robustness of the results. This is tested by examining the effects of utilizing alternative estimates of capital-energy substitution elasticities and by invoking alternative CGE closure rules.

Recall the K-E elasticities of substitution for major sectors are presented in Table 4.4.1. They range from 0.250 to 0.700, which means capital and energy are considered substitutes. It is possible that these elasticities overstate the degree of the substitutability relationship. Moreover, it is also possible that capital and energy are complements.

Note that in addition to the elasticity values in Table 4.4.1, a further substitution relationship between capital and energy in Cases 2 and 3 of the previous subsection has been modeled. In effect, a direct decrease in energy and an increase in capital by an equivalent amount and by half the amount, respectively, has been inserted essentially increasing the K-E elasticities by these quantities. Indirect effects are still modeled with the ordinary K-E substitution elasticities.

Two sets of sensitivity tests on elasticities were performed. The first reduced the K-E elasticity values by half. The overall results (not shown) yielded imperceptible differences for Cases 1 and 2 and only minor differences for Cases 3 and 4. The second set of sensitivity tests utilized elasticities for capital and energy that exhibit complementary relationships. This required recalibration of the production functions and mainly minor adjustments in other elasticities. The results of the application of these new parameters also had little affect on the results and are not presented here. In effect, the results are thus more sensitive to substitution levels across input aggregates, than within them, even for the case of interfuel substitution.

The third set of sensitivity tests is based on alternative assumptions about the labor market, factor mobility, and fiscal balances. In order to achieve equilibrium in constructing the CGE model, one cannot over- or under-constrain any of the markets. For example, in the case of labor supply, both the labor supply and wage rate fixed cannot be held fixed, nor can both of them vary. The specification of which aspect is fixed and which is variable in this and in other markets is known as a *closure rule.*

In the simulations above, a fixed real wage rate was assumed. Next the implications of an alternative closure rule that sets labor supply fixed and allows the wage rate to adjust is examined. This forces full employment of resources directly and indirectly released by the decrease in energy production. In addition, the implications of the assumption about the perfect mobility of capital are examined. Finally, the sensitivity of the result to whether carbon tax revenues are used to expand government expenditures or used for deficit reduction (with government expenditures being fixed) are examined. The conditions underlying the various sensitivity tests are presented in Table 4.4.7.

Table 4.4.7 Definitions of Subcases of Simulation 5

Sub-cases	Government Expenditure	Total Labor Supply	Sectoral Labor Demand	Total Capital Stocks	Sectoral Capital Stocks	Characterization
5.1	NF	NF	M	F	M	UNEM
5.2	NF	F	M	F	M	FULEM
5.3	NF	NF	M	F	F	S-R
5.4	F	NF	M	F	M	UNEM
5.5	F	F	M	F	M	FULEM
5.6	F	NF	M	F	F	S-R

Note: F = Fixed; NF = Not Fixed; M = Mobile

UNEM = Underemployment equilibrium; FULEM = Full employment equilibrium; S-R = Short-run case

The results of these sensitivity tests applied to Case 4 (Interfuel Substitution/Tax on All Oil) are presented in Table 4.4.8 (note that Case 4.1 is the same as Case 4 listed in Table 4.4.3). As in the original simulations, the impacts on real GNP are negative in all cases, though they are negligibly so in Cases 4.2 and 4.5 because of the employment forcing. In only two of the cases (4.1 and 4.4) are the negative impacts on GNP and employment greater than in Case 1, and then only marginally so. It appears that using carbon tax revenues for deficit reduction, rather than expanding government expenditures, does enhance negative impacts but only slightly. It also appears that a fixed capital stock assumption reduces the negative impact somewhat (Case 4.3). The explanation would appear to be that capital is prevented from leaving the U.S. (also compare the export and import figures for Cases 4.1 and 4.3).

Table 4.4.8 Interfuel Substitution Impacts, Year 2000: Sensitivity Tests (percentage change from baseline)

Case	Real GNP	Employment	Investment	Exports	Imports	Welfare[a]	Energy Use	CO_2 Emissions
4.1	-1.77	-2.28	-3.37	-2.60	-3.38	-1.64	-25.49	-27.22
4.2	-0.14	—	-2.24	-1.36	-1.60	-0.65	-24.09	-25.82
4.3	-1.34	-1.75	-3.71	-1.64	-3.20	-1.39	-22.45	-23.93
4.4	-1.79	-2.34	-1.83	-2.53	-3.25	-1.66	-25.55	-27.27
4.4	-0.08	—	2.97	-1.03	-0.99	-0.63	-24.13	-25.86
4.6	-1.50	-2.00	-1.67	-1.62	-3.17	-1.48	-22.59	-24.08

Results for individual energy sectors (not shown) are reasonably similar for all cases. The only significant difference is that crude oil imports decrease slightly in Cases 4.1 and 4.6.

4.4.5 Conclusions

The general equilibrium impacts of a conservation strategy to reduce CO_2 emissions results in a negative impact on GNP, employment, and other macroeconomic indicators. Not surprisingly, it was also found that the impact on the energy industries was also strongly negative. Potentially positive ramifications of conservation, such as cost savings, increased consumer purchasing power, and multiplier effects of investment in energy-saving equipment, were not able to offset the partial and general equilibrium downside effects of decreased energy use. Moreover, the results were robust to alternative assumptions on the degree of cost savings associated with conservation, the ease of substitution between energy and other inputs, and various macroeconomic closure rules. Finally, the results are in the ballpark of estimates undertaken by others, such as Manne and Richels (1991, 1992) and Jorgenson and Wilcoxen (1993), though these studies placed a lesser emphasis on conservation. Thus, it has been concluded that conservation should not be characterized as a "no regrets" strategy.

This does not, of course, mean that conservation is a poor strategy, but simply that it should not be oversold as costless. In addition, the scope of this review has been limited to one side of the ledger, and the existence of reasonable estimates of net benefits of reducing CO_2 emissions in the tens of billions of dollars per year for the U.S. alone (Nordhaus 1993; Boyd et al, 1995) is acknowledged.

However, it should be pointed out that a 3% decline in GNP in the Year 2000 translates into nearly $200 billion per year of opportunity costs.

Finally, it must be noted that the results pertain only to the short term. This, however, is the time period for which "no regrets" strategies apply, i.e., measures that can be taken until uncertainties about global warming are resolved. If predictions about the onset of warming are verified, a strategy need not be costless to be viable. Moreover, conservation may be able to play an expanded role in the longer term. Rather than the limited range of short-term options analyzed, in this study some researchers have proposed more sweeping "eco-restructuring" for both industrialized and developing economies (Ayres and Simonis, 1994). It is likely that these strategies would not bode well for traditional energy industries. However, their goal is to integrate innovative approaches to resource utilization into the economy so as to establish a path of sustainable development. Thus, further research is warranted to examine the long-term impacts of conservation.

4.5 Economic Analysis of the Defense Department's Fuel Mix

This activity examines U.S. military fuel consumption and describes alternative technologies that could be currently or potentially applied to the military in order to comply with U.S. government directives to lower emissions, lower dependence on imported oil and to become more energy efficient.

4.5.1 Introduction

DOD is responsible for approximately 2% of U.S. energy consumption. Of this 2%, DOD consumed approximately 34% of all aviation fuel and 33% of all distillate used for shipping in 1990 (Energy Information Agency (EIA) 1994) making DOD an important market player with respect to specific fuels. To provide perspective, Table 4.5.1 contains the breakdown of U.S. military fuel consumption with U.S. government usage and total consumption for the U.S. as a whole. It is clear that defense consumption makes up the vast majority of U.S. government use, although it only accounts for 2% of the total U.S. consumption in all of the major source fuel markets (i.e., petroleum, electricity, natural gas and coal).

EIA has made forecasts regarding certain types of fuel consumption for the years 2000, 2005 and 2010. Table 4.5.2 shows the breakdown of usage of various fuels in the military and their relative importance in terms of U.S. consumption. The military is a major user of shipping and aviation fuels that are predominantly petroleum based.

DOD energy use is divided into two major user types for the purposes of this study: 1) power and heat generation users at military installations representing fairly large expenditures on energy and; 2) transport users which represent smaller absolute amounts but larger relative amounts in terms of percentage of U.S. usage. These two categories will be used as the basis for organization of this report.

Table 4.5.1 Consumption of Energy (1992) (trillion Btu)

Fuel/Energy Type	Defense	US Government	USA
Motor Gasoline	12	35	13980
Distillate/Residual Fuel	214	236	8870
Jet Fuel	765	775	3080
Other	2	5	7540
Total Petroleum Based	993	1050	33470
%	3%	3%	100%
Electricity	117	190	9440
%	1%	2%	100%
Natural Gas	109	154	20320
%	1%	1%	100%
Coal & Other	51	65	19140
%	0.0%	0.0%	100%
Total	1269	1460	82360
% of U.S. Consumption	2%	2%	100%

Source : EIA. 1992. Annual Energy Review.

Table 4.5.2 Military Fuel Use Forecasts

Transportation Sector Energy Use by Mode and Type - Military Use
(trillion Btu per year)

Year	1990	2000	2005	2010	Annual Growth 1990-2010	1990 % of total market use
Total Military Use	902.1	656.2	660.3	670.4	-1.50%	
Aviation fuel	795	570.1	573.7	582.5	-1.50%	34.05
Residual Fuel Use	15.6	12.7	12.7	12.9	-0.90%	1.54
Distillate Fuel Use	91.5	73.4	73.9	75	-1.00%	33.11

Transportation Sector Energy Use by Mode and Type Within a Mode
(trillion Btu per year)

International Shipping

Distillate (diesel)	62.2	81.74	92.27	102.06	2.50%
Residual oil	920.24	1209.7	1356.11	1509.33	2.50%

Domestic Shipping					
Distillate (diesel)	214.19	231.25	246.36	262.96	1.00%
Residual oil	94.37	101.92	108.55	115.82	1.00%
Air Transport					
Jet Fuel	2334.55	3147.5	3509.52	3856.3	2.50%
Aviation Gasoline	45.36	42.56	42.26	42.14	-0.40%
Military Use					
Jet Fuel (Kerosene)	451.55	334.13	336.23	341.44	-1.40%
Jet Fuel (Naphtha)	343.4	235.95	237.43	241.11	-1.80%
Residual Fuel	15.58	12.66	12.74	12.94	-0.90%
Distillate	91.52	73.41	73.87	75.02	-1.00%

Source: EIA 1994.

4.5.2 Power Generation Technologies that could Lead to Changes in Fuel Consumption Patterns in the Military

A large percentage of military fuel consumption is due to the needs of military bases in terms of space heating and electricity generation for other purposes. The U.S. military has around 275 bases divided between the Army, Navy and Air Force. The fuel needs for these are divided between coal, gas and petroleum products such as distillate and heavy fuel oils.

Alternative methods to reduce fuel cost decrease dependence on imported oil and to improve environmental quality of emissions are discussed below with respect to improvements in energy management, new technologies and alternative fuels.

4.5.2.1 Energy Management Initiatives

The DOD uses approximately $2.9 billion annually in energy at military installations. The U.S. government's "Energy 2005" initiative calls for a 10% reduction in energy use at military installations by FY 1995 and a 20% reduction by 2005 (1985 is the base level). Industrial energy use is also targeted to reduce by 20% of 1985 levels in 2005.

Since the late 1970's the army has been installing Energy Monitoring and Control Systems (EMCS) at its installations. These are computer systems designed to keep track of and adjust if necessary, energy usage in order to minimize energy costs. Their development is evolutionary and implementation on large scale of the newer technologies in this field would bring significant savings in energy use due to advances in control technologies and software. MacDonald and Gettings (1991) have studied military use of such systems and concluded that "dramatic changes (in the technology) are possible in the next decade".

4.5.2.2 Flue Gas Desulfurization : "e-scrub technology"

The SERDP (Strategic Environmental Research and Development Program 1992) allocated $160 million for FY 1994 for the development for military and commercial use of the "e-scrub" flue gas desulfurization devise adapted from other military technology; according to DOD (Department of Energy 1994a) this device "may be able to efficiently turn dirty, high sulfur coal emissions into a fertilizer, resulting in cleaner water, air and a commercial product." This is but one of many flue-gas desulfurization technologies now available.

4.5.2.3 Dry Micronized Coal and Coal/Water Mixture Technology - New Boiler and Handling Technologies

The Department of Defense Appropriations Act 1986 (Public Law (PL) 99-190, Section 8110) directed DOD to rehabilitate and convert its existing domestic power plants to burn a higher percentage of coal. By FY 1994 coal consumption by the military was to have increased to 1.6 million tons per year above the level of consumption in 1985. The FY 87 Defense Authorizations Act directs that the primary fuel source used in any new heating system installed be the most life-cycle cost effective. Thus the DOD cannot install new coal-fueled plants without making sure the plant is the most cost effective over the life of the plant. These laws, together with a directive canceling the restriction that oil or gas heating systems be built on a scale smaller than 50 million Btu/h, have provided impetus for the military to look at conversion of boilers at military installations to coal.

U.S. military coal consumption from 1985 - 1991 is listed in Table 4.5.3. It can be seen that the army is the largest user of coal with the navy second largest and air force is the smallest user. It was recommended by the U.S. Army Construction Engineering

Table 4.5.3 DOD Coal Consumption (short tons)

Year	Army	Air Force	Navy	DOD Total
1985	704190	452242	162095	1336261
1986	733490	491122	168689	1409446
1987	734457	472086	163891	1384984
1988	802218	478092	178227	1471240
1989	768962	448945	222888	1453444
1990	867690	439512	178490	1498740
1991	766725	435563	167232	1381155
(% of DOD)	56 %	32 %	12 %	100 %

Source: Adapted from Lin (1993)

Research Laboratories (USACERL) in 1991 that the Navy had the highest potential for increasing its coal consumption after a study in 1987 identified bases where conversion to coal would be most advantageous.

Work by USACERL (Lin 1994) indicates that there are several choices in achieving this goal once sites for increased coal use have been identified. These include the following choices: to build new plants to replace old ones; to retrofit oil and gas boilers for coal firing; or to build third party coal fired cogeneration plants in conjunction with commercial power companies. Various technologies are available for retrofit projects (Miller et al., 1994). Briefly these are coal/water mixtures, dry micronized coal, coal gasification, retrofit fluidized-bed combustors, and slagging combustors.

So far, USACERL work as concluded that the building of new coal-fired plants to replace old oil/gas fired plants is economic at only one site. Retrofitting heavy oil plants for coal firing was found to be an attractive strategy for 38 plants of the 88 studied.

4.5.2.4 Fuel Cell Technology

The underlying principle of fuel cells has been known about for over a hundred and fifty years but the technology has only been proposed recently for commercial use. The principle is similar to how a battery works, but, unlike a battery, it continues to provide power so long as fuel and oxidant are supplied. It works by chemically reacting air/oxygen with a fuel such as hydrogen processed, using a reformer, from natural gas. This produces a direct chemical transfer of energy as a DC current which is then transformed to an AC current for use. The method of reaction means that energy efficiency is extremely high relative to thermal power plants. Newer plants are expected to produce efficiencies of 50-60% compared to 30-40% at thermal plants. Other advantages are flexibility due to their modular construction, quietness, reliability (allowing reduction in backup systems required), and environmental advantages such as extremely low NO_X, CO and unburned hydrocarbons emissions.

Fuel cells require a feedstock that enables the release of hydrogen. Alternatives include all fossil fuels. Coal gasification is among those methods currently being investigated for fuel production. Natural gas is probably the most convenient feedstock. Research and development is currently going on with respect to four types of technology based on the type of electrolyte used in the cell (see Table 4.5.4): phosphoric acid, molten carbonate, solid oxygen and proton exchange.

Canada's military has made a strategic decision to investigate fuel cell technology and has contracted Ballard Power Systems, Inc. to investigate polymer electrolyte fuel cells and their operation on air and reformate fuels. The results of the program are a demonstration program with power outputs up to 5 kW and hydrogen-oxygen and hydrogen-air low kW units have been delivered to customers. The Canadian department of defense is also sponsoring a program to demonstrate the use of 100 MWh and 300 kW Ballard fuel cells for submarine propulsion to replace diesel engines currently used. A 50 kW scaled version is being developed by Ballard that will operate on methanol and oxygen or methanol and air (on surface).

At present, units range from very low output (<10 kW) to 200 kW. In the very near future units will be available up to 10 MW. This range will probably find many uses in the military. U.S. military research has been active since the 1980's by participating in DOE, GRI (Gas Research Institute) and utility companies' field tests of 40 kW phosphoric acid fuel cell units produced by International Fuel Cells Corporation. In FY 1993, the DOD initiated a program to demonstrate and use commercially produced fuel cell power plants at sites located at military bases. DOD has also initiated a program to develop fuel cell power plants for defense applications; particularly in order to develop units fueled by standard logistic diesel or jet fuel.

Table 4.5.4 Summary of Worldwide Fuel Cell Development Progress

	<------------- Fuel Cell Status ----------->						
Country	**Phosphoric Acid (PAFC)**	**Molten Carbonate (MCFC)**	**Solid Oxide (SOFC)**	**Proton Exchange (PEFC)**	**Operating Capacity (kW)**	**Reformer made ?**	**Approx. Funding ($ U.S. Million/yr)**
Austria	Dn[1]				200		-
Australia			R,Dt				5 Total
Canada	Dn[1]			R,Dt,Dn	325		Unknown
Denmark	Dn[1]	R,Dn[1]	R,Dt	R	200	Y	4 Total SOFC
Finland	Dn[1]			R	200		-
France		R	R	R			2 Total PEFC
Germany[2]	Dn[4]	R,Dt	R,Dt	R,Dt	800		6 Gov., No PAFC
Italy	R,Dn[1]	R,Dt	R	R,Dt	1500		4 Gov
Japan	R,Dt,Dn[4],C	R,Dt	R,Dn[5]	R	+/- 40,000	Y	46 Gov.
Korea	R,Dn[4]	R,Dt	R		200	Y	Unknown
Netherlands		R,Dt	R				10 Gov.
Norway			R,Dt				2
Spain	Dn[3]	R,Dt			200		1 No PAFC
Sweden	Dn[1]	R			200		2 Gov., No PAFC.
Switzerland	Dn[1]		R,Dt		200		2 Gov., No PAFC
United States	R,Dt,Dn,C	R,Dt,Dn	R,Dt,Dn	R,Dt,Dn	+/- 4500	Y	104 Gov. & Institutes

R Research
Dt Development
Dn Demonstration
C Near Commercial or Commercial Sales

Notes:

1. U.S power plant(s)
2. Germany demonstrated a 100 kW alkaline fuel cell system in a submarine
3. Japanese power plant(s)
4. U.S and Japanese power plants
5. Westinghouse (U.S) SOFC modules

   Belgium is demonstrating an alkaline fuel cell unit in a bus.

Source: After USDOE report prepared by Gilbert/Commonwealth Inc.(1993)

The technology seems to be rapidly developing. It has a wide variety of applications due to the different scales in which it can be applied. Environmentally, the technology provides extremely low emissions energy. It is deemed more reliable and flexible than conventional thermal power/boilers. It is also more fuel efficient, therefore, implementation would result in lower fuel consumption. Its major drawbacks are that it is still very high cost technology. Current capital costs for natural gas fueled plants are estimated at between $600 – 1,000/kW, and for coal fueled plants are $1,000 – 1,200/kW.

4.5.2.5 Combined Cycle Gas Turbine

The waste heat generated in burning oil or gas in a boiler is used to run a separate turbine to increase energy efficiency. The technology has been used for many years. As such it is proven technology and, with recent advances in the technology, represents an option for new plants because it is suited to utilization of gas (now more abundant at low cost). Coal can be adapted to use in this technology through gasification of the coal and subsequent burning of the gas in the turbine (Rose et al., 1991).

4.5.2.6 Other Clean Coal Technology Programs

The Office of Clean Coal Technology (part of the U.S. Department of Energy) sponsors, in partnership with industry, a wide range of clean coal technology programs which apply to research and demonstration at various levels in the processing of coal to energy such as preparation (e.g., coal washing process developed for Phase I, Miller et al., 1994), transformation (e.g. production of "Syncoal" by the Rosebud Syncoal Partnership (U.S. Department of Energy 1994a), combustion (Miller et al., 1994), post-combustion (the SNOX process, DOE 1994a) and other relevant areas.

The Federal Government has invested $2.5 billion in the Clean Coal Technology Program; other contributions from industry and individual states have amounted to more than $4 billion (U.S. Department of Energy 1994b). As a result, 45 new demonstration projects are underway (U.S. Department of Energy 1994c). Advanced technologies are being tested in emissions reduction using scrubbers for NO_X and SO_X gases, clean coal Fuels, clean coal fluidized-bed technologies, integrated combined cycle gasification projects and other innovations. Earlier demonstration results are now being used in the design and construction of larger scale commercial facilities. It is expected that most of the 45 projects will have provided sufficient data for full scale commercialization decisions in the early years of the next century (i.e., in 5 - 15 years time) (U.S. Department of Energy 1994d).

The current drive to commercialize these technologies could affect military choice of fuel in favor of coal as the military may place more urgency on strategic considerations.

4.5.3 Transport: Technology that could Lead to Changes in Fuel Consumption Patterns in the Military

The consumption of various types of fuels could be affected by technological change in two main ways: 1) fuel economy changes and; 2) substitution to other fuels. Table 4.5.5 presents the types of transportation used in the military that are considered in this analysis. The currently used fuels are noted as well as possibilities for conversion either physically or by re-equipping the fleet with new engines/vehicles.

4.5.3.1 Alternative fuels

Currently, conventional fuels are those most widely in use including gasoline and diesel for land based vehicles and residual oil and distillate for ships and kerosene/naphtha for aircraft. DOD is now under pressure to have their consumption reduced for two main reasons: 1) to reduce reliance on imported oil (a strategic issue); and 2) to reduce harmful emissions caused by their use, especially those used in land-based applications, for environmental reasons.

Alternative fuels have characteristics that make them more attractive than conventional fuels on strategic and/or environmental grounds. Table 4.5.6 lists currently known alternative "fuels" in the broad sense (including nuclear and electric technologies), the conventional fuels that they replace and the technologies that are now being developed to exploit them in either the military or private/civilian sectors.

In terms of projects already under way the DOD has undertaken to convert a portion of its 200,000 administrative vehicles (assumed to include all buses, trucks, LDV's, automobiles and other such) to "alternative fuels". By FY 1995 the DOD has undertaken to acquire 10,000 alternative fuel vehicles.

Table 4.5.5 Possibilities for Conversion of Vehicles to Alternative Fuels

Mode of transport	Main Fuel	Possibilities for Conversion
Light vehicles	diesel/gasoline	CNG,LNG,LPG,M-85,M-15,E-95,E-100,M-100, electricity, H-Fuel Cell
Buses	diesel/gasoline	CNG,LNG,LPG,M-85,M-15,E-95,E-100,M-100, electricity, H-Fuel Cell
Trucks	diesel/gasoline	CNG,LNG,LPG,M-85,M-15,E-95,E-100,M-100, electricity, H-Fuel Cell
Ships	distillate residual fuel - oil ? nuclear	Fuel cells, CNG,LNG,
Jet aircraft	jet fuel JP-8, JP-4, (kerosene, naphtha)	Coal gasification derived JP-8
Helicopters/prop aircraft	kerosene	Coal gasification derived JP-8
Tanks & other armored vehicles	diesel ?	

4.5.3.2 State and Federal Government Initiatives and Legislative Aspects

1970s oil price increases and current environmental concerns have lead to governmental sponsoring of and influence over efforts to introduce alternative fuel use. The Clean Air Act Amendments of 1990 set goals for improvement of air quality especially concerned with CO (carbon monoxide) and O_3 (ozone) emission reduction in the transport sector. The law is viewed as favorable towards alternative fuels such as chemically simpler fuels (e.g., methanol and methane).

The Energy Policy Act of 1992 (EPACT) was passed in the wake of the Persian Gulf War of 1990-1991. This act set out to decrease independence of the U.S. on imported oil. The act targets fleets of vehicles for increased use because of the costs of conversion, refueling and fuel storage facilities. EPACT mandates acquisition targets for alternative fueled vehicles for Federal and State agencies.

Table 4.5.7 illustrates how, under EPACT, the federal government (including the DOD) will be required to increase the numbers of alternative fuel vehicles rapidly in the next 5 years. 75% of all new federal vehicles acquired in 1999 will have to be alternative fuel powered vehicles. New military vehicles will undoubtedly be affected by these regulations.

Table 4.5.6 Alternative Fuels and Technology Developments for Transportation

Alternative fuel	Conventional fuel replaced	Technologies available	Development stage
Compressed natural gas (CNG)	Gasoline Diesel	Light Duty vehicles: Buses and other heavy duty vehicles.	Demonstration
Liquefied natural gas (LNG)	Gasoline Diesel	Light Duty vehicles: Buses and other heavy duty vehicles.	Demonstration
Liquefied Petroleum gas (LPG) (Propane)	Gasoline Diesel		Demonstration
Methanol/gasoline (M-85)	Gasoline Diesel	Cars, trucks, heavy duty vehicles	Demonstration/ Commercial
Methanol (M-100)	Gasoline Diesel	Cars, trucks, heavy duty vehicles	Demonstration/Co mmercial
Ethanol (E-95, E-100)	Gasoline Diesel	Cars, trucks, heavy duty vehicles	Demonstration/Co mmercial
Ethanol/Gasoline (E-10[1], E-15[1], E-85)	Gasoline	Cars, trucks, heavy duty vehicles	Demonstration/Co mmercial
Electricity	Gasoline Diesel	Cars, trucks, heavy duty vehicles	Demonstration/Co mmercial
Reformulated gasoline[2]	Gasoline Diesel	Cars, trucks, heavy duty vehicles	Demonstration/Co mmercial
Fuel cell	Gasoline Diesel	Methanol fueled bus - Mercedes, GM, Chrysler - also cars, trucks and plans for locomotives	Demonstration

Notes:

[1]These fuels are statutory not defined as "alternative" in EPACT but are defined as "replacement"
[2]These fuels are aimed at lowering emissions regardless of source (and thus strategic influence).

Source: EIA. June 1994.

4.5.4 Conclusions

It is shown that for both power/heat generation and transport applications there is a wide variety of possible alternatives that could be applied for military use. Many new coal technologies such as dry micronized coal, fluidized bed, flue-gas desulfurization, coal gasification, combined cycle and advanced combustors are currently being implemented and designed (Miller et al., 1994).

Table 4.5.7 Alternative Fueled Vehicle Targets for the Federal Fleet as proposed in Two Pieces of Legislation.

Fiscal Year	EPACT Requirements	Executive Order 12844
1993	5,000	7,500
1994	7,500	11,250
1995	10,000	15,000
1996[1]	25% of acquisitions	-
1997[1]	33% of acquisitions	-
1998[1]	50% of acquisitions	-
1999[1]	75% of acquisitions	-

Notes:
[1]Percentage of acquisitions in these years is based on light duty vehicle acquisitions. The Executive Order did not provide AFV targets or percentage acquisition for these years.

Source: EIA. June 1994.

Energy use in the military could also be significantly affected by new energy management systems and implementation of modified, more efficient, conventional technology.

Fuel cells appear to be a fast emerging technology for both generation and transport applications, with small scale power applications currently closest to proven commercial use. Numerous commercial and demonstration programs are underway regarding use of alternative fuels in transportation. Many of these, including fuels for fuel cell use, could use coal as a feed stock if processed by gasification or liquefaction either on site or at processing plants prior to distribution.

4.6 Constructing a National Energy Portfolio which Minimizes Energy Price Shock Effects

4.6.1 Introduction

Investors have long sought to reduce their exposure to market swings by holding a diverse mix of investment instruments, which can reduce investor risk dramatically. By examining the variance, covariance and expected return between a group of assets, Markowitz (1952) constructed an efficient portfolio that maximized expected return for a given level of risk. The dual goal of maximizing return while minimizing variance produces a set of efficient portfolios an agent can chose from according to his or her personal preferences.

Portfolio theory and diversification have proved useful in areas other than personal and corporate investing. Adegbulugbe et al. (1989) examine the long-term optimal structure of the Nigerian energy supply mix. They use a multiperiod linear programming model of the total energy system to minimize direct fuel costs while maintaining balanced development. Bar-Lev and Katz (1976) examined fuel procurement in the electric utility industry and created a Markowitz efficient frontier of fuel mixes which minimizes expected fuel costs and risk. Electric utilities rely heavily on long-term contracts with price adjustment clauses for fuel supplies. The possibility of price increases (or decreases) creates an atmosphere of uncertainty which must be factored into the fuel procurement decision, not unlike the problem of selecting risky securities. Kroner and Claessens (1991) show how diversifying the composition of a country's foreign debt can act as a hedge against changes in exchange rates and commodity prices. The conditional covariance matrix of exchange rates and terms of trade, which changes through time, determines the optimal portfolio.

This section uses portfolio theory to demonstrate how the energy mix consumed in the United States could be chosen if the goal is to reduce the risks to the domestic macroeconomy of unanticipated energy price shocks. An efficient portfolio frontier of U.S. energy consumption is constructed using time-varying variances and covariances estimated with generalized autoregressive conditional heteroskedastic models. This allows the efficient portfolios to shift over time in response to price changes and past volatility. A trade-off between risk and cost exists. The set of efficient portfolios developed are intended to minimize the impact of price shocks, but are not the least cost energy consumption bundles. Although linear or quadratic programming techniques could also provide estimates of a unique optimal energy mix, the portfolio methodology is superior because it creates a set of efficient energy mixes, which vary in response to market events, and leaves the final choice to policy makers.

The United States government, through national energy policy, has long attempted to decrease the domestic economy's exposure to the impact of an energy shock.

Such attempts have included quotas on imported oil, greater self-sufficiency in energy, increased research into alternative fuel sources, the strategic petroleum reserve, and increased domestic coal consumption. Underlying this goal was the belief that decreasing the heavy dependence on oil, and foreign oil in particular, would limit the potential effects of a price shock from a single energy source. As recently as 1993, Secretary of Energy for the Clinton Administration Hazel O'Leary called for further diversification of U.S. energy consumption.

A negative correlation between oil prices and real output has been well established empirically. Fried and Trezise (1993) state that the 1973 oil shocks increased the general rate of inflation by two percentage points, led to a term of trade loss for oil importing countries equal to 1.5 to 2% of the GNP, and decreased economic output by two to three percent within OECD countries. Rasche and Tatom (1981) estimate a 7.0% average long-run reduction in U.S. GNP following the 1973-1976 oil shocks, Darby (1982) estimates a 2.5% decline, and Hamilton (1983) confirms the negative relationship between oil prices and real output for the U.S. both before and after the price increases of the 1970s. Mork et al. (1994) found this correlation persists in data through 1992, including the Persian Gulf War of 1991.

The goal of minimizing exposure to foreign oil price shocks by reducing oil imports ignores the possible covariance relationships between different energy sources. Shocks in the oil market can spill over to the coal and natural gas markets, and the relationship between domestic and foreign oil prices is strong and positive. Thus, establishing a goal of oil independence will not buffer the U.S. economy from foreign oil price shocks unless accompanied by the total isolation of the entire domestic energy market from the world market. As Heal (1992) notes, a choice of isolation would create artificially high energy prices domestically and be economically inefficient. A better solution is to look for those combinations of oil, natural gas, and coal where price volatility in one fuel is offset by opposing volatility in another fuel, as portfolio diversification and management are designed to do.

4.6.2 Methodology

The primary goals of a rational investor are to maximize expected return and minimize risk. Higher risk is usually compensated for by higher expected returns. By purchasing a combination of assets, an investor can generate the highest possible return to their investment dollars at the least possible risk. The expected return of such a portfolio depends on the expected returns of the individual assets and the relative percentage of funds invested in each. The risk of the portfolio depends on the degree of risk of the assets and the covariance or correlation of the assets. While the correlation has no impact on portfolio return, it plays an important role in determining the risk associated with the portfolio. The lower the correlation between two assets, the greater the risk reduction potential when combining them in a single portfolio.

The expected return for an *n*-asset risky portfolio is

$$E(R_p) = \sum_{i=1}^{n} w_i E(R_i) \tag{4.6.1}$$

where $E(R_i)$ is the expected return from asset *i* and w_i is the weight of asset *i* held in portfolio *p*. The corresponding risk of such a portfolio, as measured by its variance, is

$$\sigma_p^2 = \sum_{i=}^{n} \sum_{j=}^{n} w_i w_j \operatorname{cov}(i, j) \tag{4.6.2}$$

where *cov(i, ,j)* is the covariance between two risky assets *i* and *j*. By varying the weights of the assets, a set of potential portfolios can be generated. The efficient portfolio frontier is the subset of all dominant portfolios from the set of all possible portfolios. In a dominant portfolio, return cannot be increased while holding variance constant and variance can not be decreased while holding return constant. Assuming risk aversion in decision makers, rational choice should lead to investment decisions only on the efficient frontier.

The return and variance of any portfolio can be calculated and the efficient frontier generated as long as the expected return of each asset and the covariance matrix is known (equations 4.6.1 and 4.6.2). In their analysis of the electric utility industry, Bar-Lev and Katz (1976) use a quadratic programming approach to estimate these values. However, such a methodology requires the covariance matrix to remain constant over time, regardless of any new information which enters the market. Allowing the covariance matrix to be systematically updated over time as new events occur provides more realistic and efficient estimates. The generalized autoregressive conditional heteroskedasticy process (GARCH) introduced by Engle (1982) and Bollerslev (1986) allows the error variance and covariance to respond to price shocks and changes in volatility. GARCH has been used extensively for modeling financial time series. Bera and Higgins (1993) and Bollerslev et al. (1992) provide surveys of the GARCH literature.

The GARCH(p,q) process is defined in terms of the properties of the distribution of the error terms in the model

$$Y_t = X_t'\partial + \varepsilon_t \qquad \varepsilon_t \ i.i.d., \qquad t=1,...,T \tag{4.6.3}$$

where X_t is a $kx1$ vector of exogenous variables which can contain lagged dependent variables, ∂ is a $kx1$ vector of regression coefficients, and ε_t is the error term. ε_t is assumed to have a traditional constant unconditional variance, but its conditional distribution depends upon the information set ψ_{t-1}, or

$$\varepsilon_t | \psi_{t-1} \sim N(0, h_t) \tag{4.6.4}$$

where

$$h_t = c_o + \sum_{i=1}^{q} \alpha_i \varepsilon_{t-i}^2 + \sum_{j=1}^{p} \beta_j h_{t-j}. \tag{4.6.5}$$

The conditions ensuring non-negativity and stationarity can be found in Nelson and Cao (1992). The conditional variance h_t is a function of the information set ψ_{t-1}, and the underlying functional form effectively models the volatility clustering commonly seen in financial time series data. The generalized GARCH(p,q) model allows the present conditional variance to depend on past conditional variances in addition to past squared innovations.

Computing time-varying covariances requires the simultaneous estimation of a multivariate system (Bollerslev et al., 1988). Generalizing a univariate GARCH model to a multivariate model requires allowing the entire covariance matrix to change with time, rather than just the variance. Thus, the elements of the covariance matrix would be linear functions of lagged squared errors, lagged cross-products of the errors, lagged variances, and lagged covariances. The traditional means of estimating such a system, similar to a vector autoregression, is cumbersome and sometimes impossible. Bollerslev (1990) has suggested a multivariate GARCH specification which holds the correlation matrix constant over time. Using the relationship between covariance and correlation,

$$h_{ij,t} = \rho\sqrt{h_{i,t}h_{j,t}} \tag{4.6.6}$$

each period's covariance can be calculated. This allows the variance and covariance to change over time while the fundamental relationship between assets remains unchanged. The constant correlations model has been used successfully with foreign exchange rate data (Bollerslev 1990) and interest rate data (Cecchetti et al., 1988). Giovannini and Jorion (1989) find the estimated variances from a constant correlation estimation are almost perfectly correlated with the estimated variances from the VAR-type estimation, and Baillie and Bollerslev (1990) show that the data does not usually reject the constant correlation assumption.

The analysis of energy portfolios differs slightly from investor portfolio analysis. Since every energy investment has risk, no risk-free energy asset is available. Another difference is the inability of energy investors to hold negative weights of, or "go short on," an energy type. The equivalent to shorting stock in energy investment would be using electricity to create natural gas and then selling the natural gas, but it is impossible to efficiently create natural gas from electricity.

4.6.3 Estimation and Results

The data set consists of monthly spot energy price series of oil, natural gas, and coal. Over the next ten years, 85% of new non-nuclear electric generation in the U.S. is projected to be from these three sources. Further investment in nuclear energy production has been stalled and much current production will be phased out over the next 20 years. The share of hydroelectricity and other non-conventional energy sources is not expected to grow over the next decade. Few new potential hydro power sites exist in the United States, and non-conventional energy sources are not currently competitive on a large scale and will likely not be so over the next ten years.

Two price series were obtained for each energy source, both nominal and not seasonally adjusted. Basic energy costs were derived from average monthly first nearby oil prices and natural gas prices from the NYMEX and average wellhead price for periods before NYMEX trading. The coal price series is the average spot price paid by electric utilities as reported to the Federal Energy Regulatory Commission. All prices are in terms of monthly million Btu/$. The second set of price series adds electric utility non-fuel costs to basic energy costs to generate a total operating cost for electricity generation from each energy source. The data extend from January 1974 to August 1995 (260 observations) and are plotted in Figure 4.6.1.

Each series is tested for the presence of a unit root. A series with a unit root is nonstationary with an infinite unconditional variance. The results of Dickey-Fuller and augmented Dickey-Fuller tests are reported in Table 4.6.1. All series fail to reject the null hypothesis of a unit root at the 95% confidence level. Thus, to achieve stationarity in the data, all series were differenced once.

Table 4.6.2 presents the historical moments of each series. The spread between the average MM Btu/$ (column 1) is smaller in the utility energy cost group than the raw energy cost group. This reflects the inverse relationship of fixed costs to variable costs. In general, oil has provided the least MM Btu/$ for an investment while natural gas has provided the most. Examining the first differenced log for each series, the mean return is not significantly different from zero and all exhibit skewness and excess kurtosis. This is reflected in the high Bera-Jarque statistic, which rejects the null of a normal distribution at 0.05% in all cases.

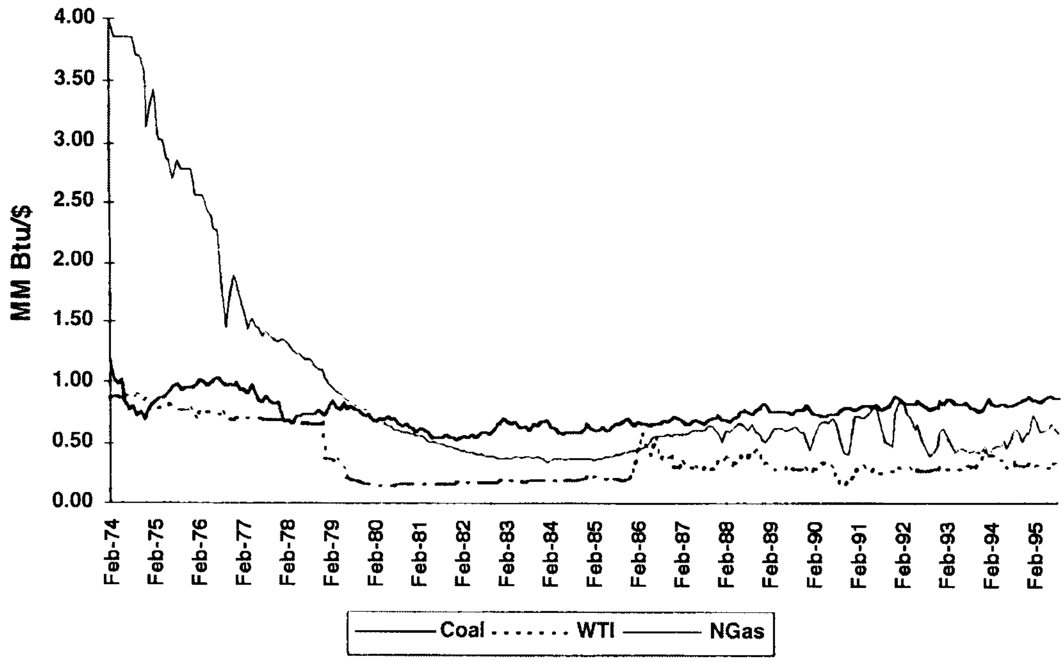

Figure 4.6.1 HISTORICAL ENERGY RETURN (MM BTU/$) FOR EACH ENERGY TYPE

Table 4.6.1 Unit Root Tests

	AR Parameter	DF Statistic	ADF Statistic	Number of Significant Lags
Coal	0.9544	-2.748	-2.748	0
Natural Gas	0.9754	-2.148	-2.120	12
Crude Oil	0.9762	-1.788	-2.269	1

The 5% and 10% critical values for Dickey-Fuller tests are -2.84 and -2.57.

Lags were considered significant at the 10% level.

Table 4.6.2 Historical Moments of Price Series

	Average MM Btu/$	Differenced Log MM Btu/$				
		Mean	Variance	Skewness	Kurtosis	Bera-Jarque
Raw Energy Costs						
Coal	0.76	-0.0021	0.0021	-0.98	6.1	146
Oil	0.38	-0.0036	0.0068	-0.84	12.6	1016
Natural Gas	0.95	-0.0077	0.0068	0.79	8.4	336
Utility Energy Costs						
Coal	0.43	-0.0010	0.0007	-0.64	4.3	36
Oil	0.28	-0.0026	0.0043	-0.68	11.7	842
Natural Gas	0.53	-0.0040	0.0035	0.89	9.0	425

Table 4.6.3 reports the correlation matrix between the price series. The correlations are generally small, with the relationship between coal and both oil and natural gas weak whether or not non-fuel costs are included. Natural gas and oil have a slightly larger though still small correlation coefficient. The relationship between natural gas and oil in the last five years of the data set (1990-1995) has become stronger, with a correlation coefficient of 0.40, probably because of the deregulation of natural gas.

Table 4.6.3 Correlation of Changes in Monthly Energy Return (MM Btu/$) Series 1973-1995

	Basic Energy Costs			Electric Utility Operating Costs		
	Coal	Natural Gas	Oil	Coal	Natural Gas	Oil
Coal	1			1		
Natural Gas	0.02 (0.46)	1		0.02 (0.46)	1	
Oil	-0.01 (-0.16)	0.13 (3.61)	1	-0.01 (-0.18)	0.12 (3.47)	1

The GARCH parameter estimates for equations 4.4.3 and 4.6.5 are found in Table 4.6.4. The significance of $\hat{\alpha}$ and $\hat{\beta}$ in the variance equation (equation 4.6.5) supports the choice of a GARCH model in place of a homoskedastic system. Predicted volatility for each of the energy price series based on the parameter estimates is plotted in Figure 4.6.2. Coal prices are the most stable, with a relatively constant conditional variance and return. Oil shows significant volatility increases during each historic price shock (i.e., 1979, 1986, 1991) and an overall trend to increasing volatility in the 1990s. These price shocks affect oil volatility for approximately one year. Natural gas shows the most marked change. Returns to investment have declined significantly as prices have increased over the last twenty years. Natural gas prices have also been very volatile in recent years, reflecting the deregulation of the natural gas industry and the development of active natural gas futures markets.

Combining the parameter estimates and the correlation coefficient estimates according to equation 4.6.6 yields estimates of the time-varying covariances of the system. Energy portfolios are constructed using these covariances and expected returns in equations 4.6.1 and 4.6.2. Figure 4.6.3 depicts the efficient portfolio frontier in 1990 for both basic energy costs and electric utility operating costs. The addition of fixed costs to energy costs lowers returns to electric utilities and results in a lower curve. The additional fixed charges also mean that the annual volatility becomes smaller relative to the absolute size of the costs, shifting the curve to the left.

When viewing the actual energy portfolios of U.S. consumption for 1980, 1990, and 1995 along with an example of an efficient portfolio from the estimated portfolio frontier for each year, it is noted that the actual energy consumption portfolio is far from efficient. The efficient portfolio Sharpe ratio is two to three times the size of the actual portfolio ratio. In general, a more efficient consumption bundle would include a higher percentage of coal and less oil and natural gas in the overall economy. Increasing coal consumption would both decrease volatility and increase energy return, a movement to a dominant portfolio. It is acknowledged that the effective price of utilizing fuels differs from the market price somewhat. Given market imperfections, relatively higher costs of pollution mitigation associated with coal may not have properly been reflected, and similarly for uncertainties related to deregulation of natural gas.

Table 4.6.4 GARCH Estimation of Energy Return Series (T-statistics in parenthesis)

	Mean Equation Eqn. 9-3		Variance Equation Eqn. 9-5	
	δ	c	α	β
Raw Energy Costs				
Coal	0.001	0.0001	0.068	0.72
	(0.61)	(2.81)	(2.94)	(9.58)
Natural Gas	-0.014	0.00002	0.096	0.83
	(-6.22)	(2.40)	(4.57)	(26.87)
Oil	-0.005	0.0008	0.183	0.40
	(-1.75)	(5.86)	(4.47)	(4.65)
Electric Utility Operating Costs				
Coal	0.001	0.00003	0.077	0.72
	(0.70)	(2.42)	(3.02)	(9.41)
Natural Gas	-0.010	0.00005	0.208	0.62
	(-6.49)	(4.17)	(5.08)	(11.70)
Oil	-0.004	0.00047	0.194	0.41
	(-1.63)	(6.02)	(4.78)	(5.15)

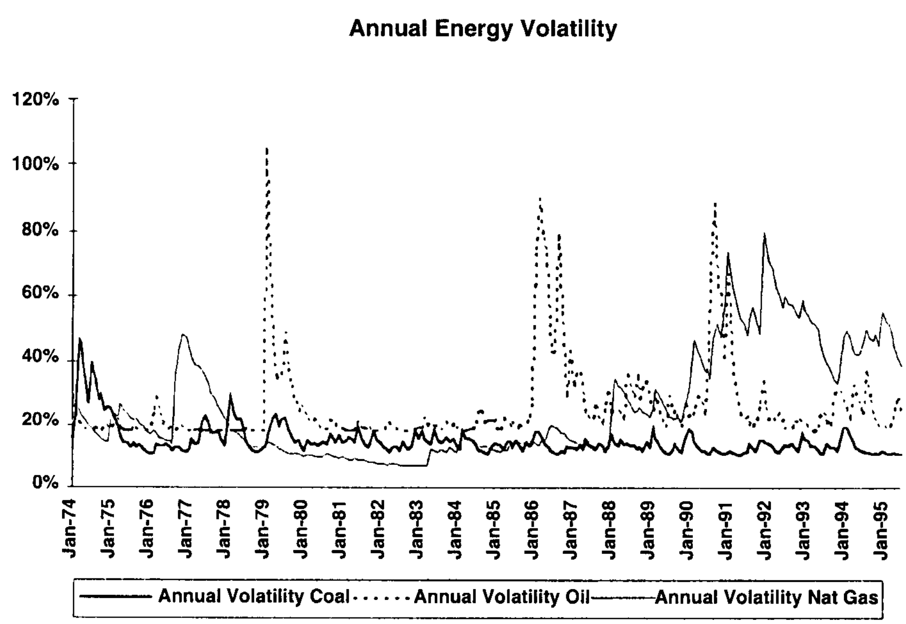

Figure 4.6.2 GARCH ESTIMATES OF ENERGY RETURN VOLATILITY

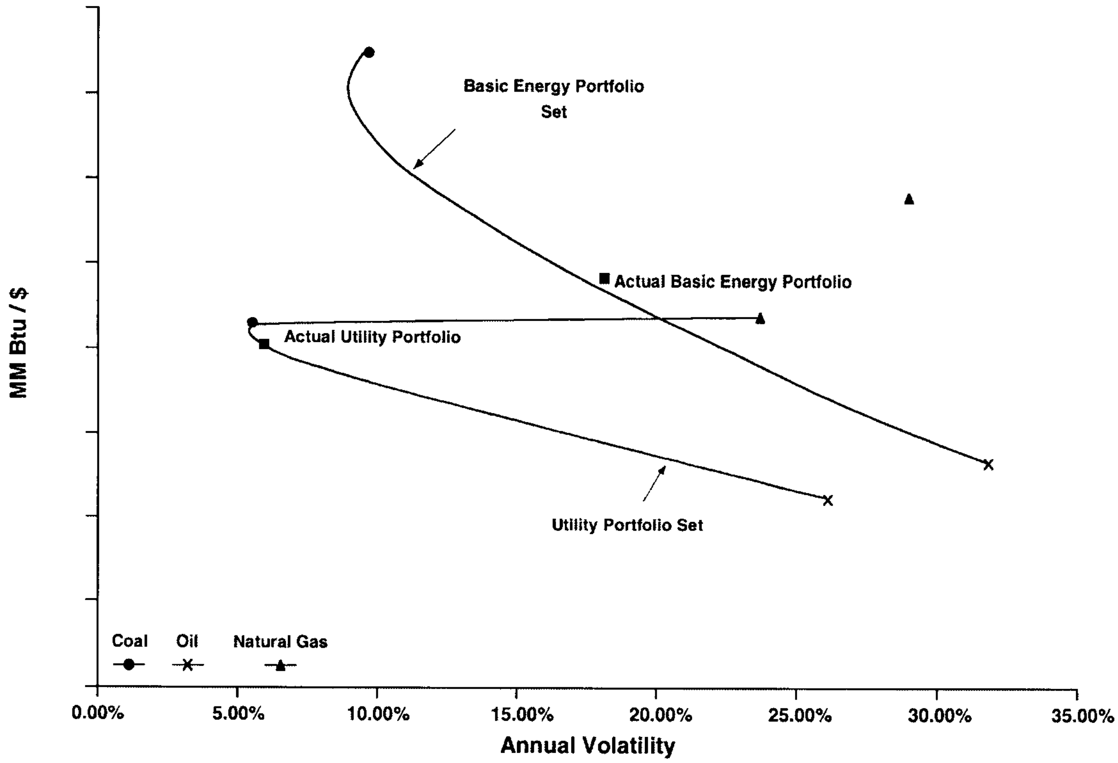

Figure 4.6.3 1990 EFFICIENT PORTFOLIO FRONTIERS FOR THE UTILITY INDUSTRY AND GENERAL U.S. CONSUMPTION

For the total costs faced by the electric utility industry (energy costs plus nonfuel costs), operation has moved towards more efficient portfolios since 1980. In 1990 and 1995 the industry operated very close to the efficient frontier. The industry also operated at a position of very low volatility. The high level of coal consumption by utilities suggests a relatively high level of risk aversion, in contrast to the results of Bar-Lev and Katz (1976), who found electric utilities pursuing high-risk consumption strategies. They argued that this was the result of regulatory policy that allowed electric producers to pass cost through to the consumer. However, the price shocks and volatility in the oil market since their study might have shown the limit of such regulatory largesse and have led to the observed increase in risk aversion seen by the utility consumer.

As the variance and covariance changes over time in response to price shocks and past volatility, the efficient portfolio set also changes. Some general observations can be made. Certain relationships remain unchanged. Coal is more stable than either oil or natural gas. Natural gas tends to be more volatile than either coal or oil, with superior returns to the electric utility industry and lower returns in the overall energy portfolio.

4.6.4 Policy Recommendations

The actual energy portfolio selected should be determined by the tangency of the efficient portfolio frontier and the utility curve which reflects the country's preferences regarding risk and return. Some general recommendations can be offered. The volatility (but almost certainly not the level) of overall U.S. energy consumption costs could be lowered (and expected returns raised) by increasing the percentage of coal within the overall consumption mix. Lower volatility should lead to fewer disruptions in the domestic macroeconomy. The actual level of each energy source should be determined by feasibility and the utility curves of the country. Shifting as far as 70% coal consumption (Table 4.6.4, 1990) would be physically impossible since coal is best used in boilers, which account for far less than 70% of U.S. energy consumption. Choice is valuable because the ability to easily switch between fuels to adjust the consumption mix allows the fuel mix to move with the efficient frontier in response to market events. Discovering ways to move cheaply from one fuel to another would be desirable.

The recommendation to shift energy consumption towards coal rests on the premise that future coal price movements are similar to historic prices. This may not be the case. The deregulation of the electric utility industry and potential introduction of coal futures contracts may lead to an increase in coal price volatility similar to that seen in the natural gas industry. However, for the near future, coal prices should remain relatively constant.

Although transparent future markets exist in oil and natural gas and there exists an active coal market, the market price of energy does not reflect the true cost of energy consumption due to the presence of externalities. Environmental, national security, monopoly, and depletion costs may not be adequately included in the market price. These costs can be incorporated into the analysis by including an estimated externality cost in the total cost of an energy source. This creates a new set of variances, covariances, and expected returns, and thus a new set of efficient portfolios from which to choose an efficient portfolio. The portfolio framework also allows selection of portfolios for sectors that may face different externality costs. The sector would construct an efficient portfolio frontier using their own externality costs and then choose from this frontier. Even with the use of portfolio analysis to select a consumption bundle, a remaining inefficiency may arise due to over-consumption of energy in general. Substitution away from energy should take place as its costs rise.

As an illustration, consider the environmental costs associated with energy consumption. Many estimates have been made of the environmental costs of energy consumption, optimal tax rates, and carbon taxes (e.g., Viscusi et al., 1989; Verleger 1993). Barbir and Veziroglu (1991) estimate that the total costs of energy consumption in 1990 were $2.36 trillion dollars with estimated externality costs of $9.31/MM Btu for coal, $8.03/MM Btu for oil, and $5.31/MM Btu for natural gas. Adding these cost estimates to the energy cost data creates a new set of efficient portfolios, illustrated in Figure 4.6.4 for 1990. Including environmental costs greatly decreases energy returns and gives natural gas a higher return than coal. Although the minimum variance portfolio is the same in both this and the previous analysis (64% coal, 19% oil, and 17% natural gas), every other point on the frontier is different. Ignoring environmental costs leads to a decision to increase coal consumption to reduce volatility. Including environmental costs shifts consumption away from coal towards natural gas in order to increase the portfolio's return. Because the analysis is highly sensitive to the estimates of externality costs used, reliable estimates are essential.

Of frequent political interest is the potential security premium representing the benefit of self-sufficiency in energy needs. Like the disagreement which exists over the size and actual impact of energy price shocks on the domestic economy, discrepancies also exist in the size and even existence of a security premium. Bohi and Toman (1996) provide an overview of security premia estimates from the Department of Energy which range from $0.17/bbl of oil to $10/bbl of oil. Heal (1992) estimates that between additional defense and strategic petroleum reserve spending, the national security expenditure in 1985 was approximately $9/bbl of imported oil.

To illustrate the effect of a security premium on portfolio choice, $10/bbl is added to the total oil price. Figure 4.6.5 illustrates the resulting efficient frontier. Again, the minimum variance portfolio remains unchanged, but for the same expected return a

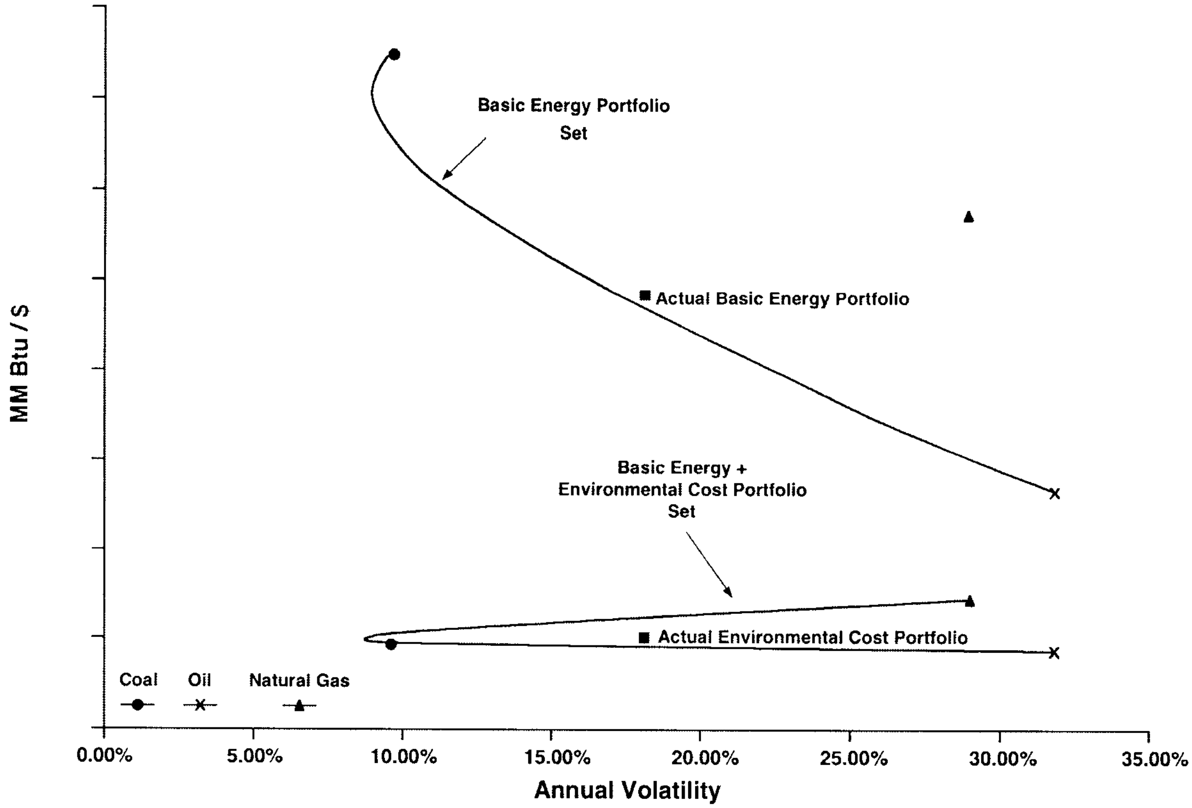

Figure 4.6.4 1990 EFFICIENT PORTFOLIO AND EFFICIENT ENVIRONMENTAL PORTFOLIO

different portfolio composition arises. On average, the portfolios including a security premium include 5% less oil than the portfolios based solely on market costs. Groups such as the U.S. military, who may place a higher premium on the use of imported oil, would want to shift even more of their oil consumption towards coal.

4.6.5 Conclusions

This section has introduced a method for choosing efficient energy mixes which would reduce the risk to the domestic economy of energy price shocks. A frontier (range) of possible portfolios is generated from which policymakers must choose a desired portfolio based on their risk and expected returns preferences. The results indicate that the electric utility industry is operating very close to the minimum variance position with a risk aversion strategy. In contrast, overall energy consumption in the United States is far from an efficient mix. A shift towards coal consumption would reduce price volatility. With the inclusion of potential externality costs, the shift remains

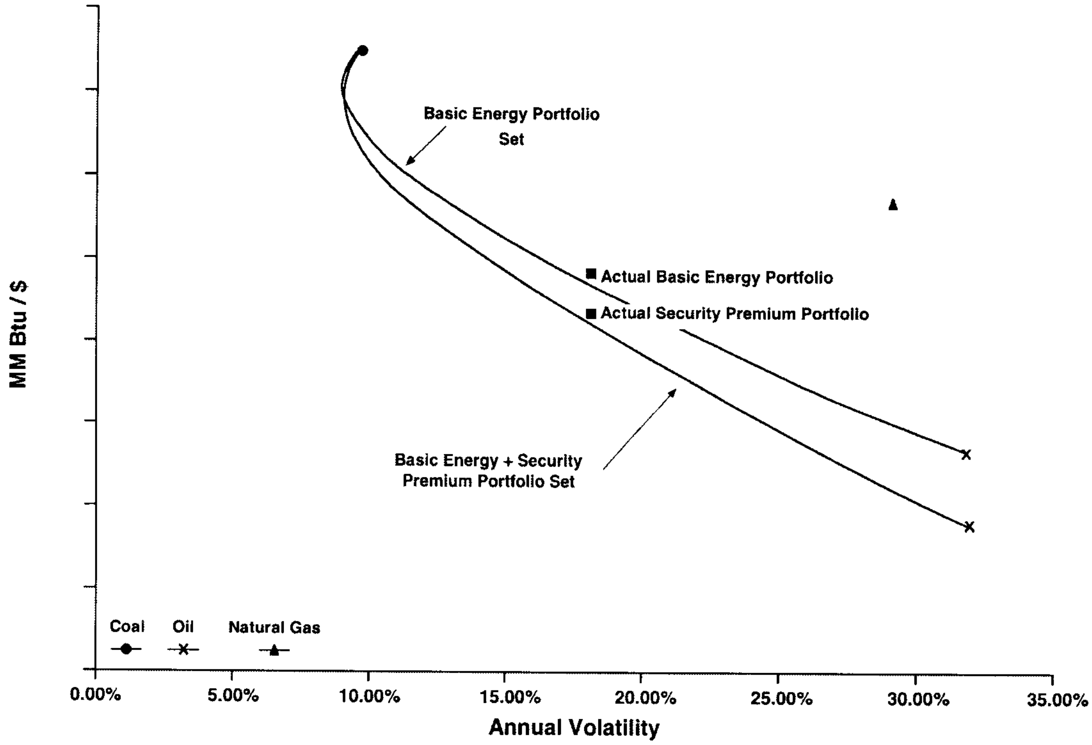

Figure 4.6.5 1990 EFFICIENT PORTFOLIO WITH AND WITHOUT A $9.00/BBL SECURITY PREMIUM

away from oil but towards natural gas instead of coal. To achieve such shifts, policymakers could use regulation or tax incentives to industries to encourage the use of certain fuels. Of course, a minimum risk portfolio does not imply a minimum cost portfolio, and selecting a low-risk portfolio may lead to higher energy costs overall. The costs associated with an occasional energy price shock may be far less than the cost associated with energy independence or a dramatic shift towards coal, synfuels, and other alternative energy sources.

4.7 Proposed Research on the Coal Markets and their Impact on Coal- Based Fuel Technologies

4.7.1 Historical and Prospective Changes in Electric Power Coal Use 1947-1993

The following discussion is based primarily on data taken from the Statistical Yearbook for the Electric Utility Industry (Edison Electric Institute 1977), Trends in

Electric Utility Industry Experience (National Coal Association 1960), and Electric Power Annual (U.S. Department of Energy 1986a, 1986b, 1993a, 1993b, 1993c). Several factors in fuel markets as well as in government regulation affected the choice of fuels. Among the major fuels, the tradeoff is between fuel and capital costs. Coal and nuclear power have relatively low fuel costs but require large capital investments. Natural gas and oil have relatively more expensive fuel costs but have lower capital costs.

Three major factors affecting fuel choice are: first, fuel prices differ markedly in different regions of the United States therefore there are regional differences in fuel choice; second, intervention by the U.S. government via Federal power projects, general regulations of specific fuels, regulations affecting fuel use in electric utilities and air pollution regulations; and third, the changing status of the world oil market.

The choice of fuels in the electric utility industry has been based mainly on fuel cost and capital costs. Over time, regulatory pressures have increased capital and operating costs, particularly in nuclear and coal-powered power plants. Natural gas has been the dominant fuel only in the West South Central region and California. Historically, these regions used gas largely produced within the region. Oil-based generation saw a dramatic increase after the deregulation of imports of residual fuel oil in 1966 then a rapid decrease after the 1973 and 1978 OPEC oil shocks.

Hydroelectric generation has a declining share of generation. Capacity expansion failed to keep up with demand growth except in the Northwest region.

A principal regulatory impact on the choice of fuels in the electric utility industry is the Clean Air Act of 1963 and its subsequent amendments. The act is a disincentive to coal use and promotes natural gas in electricity generation.

4.7.1.1 Air Quality Legislation

The main areas initially affected by air quality legislation were the Northeast and Midwest area of the U.S. while other areas, such as the Western and Southern regions were not as affected. However, from the early 1970s to the 1990s, coal's share of generation grew dramatically in the West South Central region. In contrast, the Eastern region of the U.S. saw little or no growth in coal's share of generation. Texas became a large producer of lignite. This, and a move to Wyoming subbituminous coals meant a shift away from gas and oil towards coal as a major fuel source. In the other West South Central states, the pattern was similar but not as dramatic.

California has instituted its own air quality regulation before the Clean Air Act of 1963 restrictions went into force due to severe air quality problems. These regulations and other policies in effect precluded California from using coal to generated electricity. New York state and New Jersey also instituted air quality legislation that made coal generation undesirable and thus favored less polluting fuels such as natural gas and oil (Sanders 1983).

4.7.1.2 Influence of Regulations on Fuel Use

A complete review of the influences of regulations and cost factors on fuel selection, i.e., natural gas, nuclear power, hydroelectric power and oil, in electric utilities is presented in an unpublished master's thesis (The Pennsylvania State University) titled "Fuel Use in United States Electric Utilities, Developments 1947-1993" by Aabakken (1995). The following discussion will pertain only to the use of coal in the electric power generation industry.

The economics of coal have been more stable compared to the competing fuels. Coal prices have not endured the kind of regulatory pressure that oil and gas have and the prices of coals have been less volatile. However, coal has had regulatory impacts that are present today and will last for decades.

One form of regulation on the producer side of coal has been for mine reclamation. Federal surface coal mine regulation legislation required that strip coal mines reclaim the land to return it back to its past level of usefulness as an integral part of the mining process. Extensive remediation measures also need to be installed to prevent acid mine drainage. Despite the added costs of all these measures, the coal industry's productivity gains seem to have negated any price increases. The price of coal has consistently been lower than oil or gas. As such, this legislation does not seem to have placed coal in a disadvantaged situation with its competitors.

The Clean Air Act of 1963 has had a significant influence as a disincentive for coal use. In 1978, Congress passed the Best Available Control Technology (BACT) requiring new coal burning plant to employ devices to reduce SO_2 emissions. Ultimately this regulation resulted in a move away from coal as the favored fuel for expansion of capacity. In 1993, no coal plants were added to the electric utility industry. Natural gas became the favored fuel for capacity expansion.

4.7.1.3 Slower Generation Growth

Electric generation varied with economic activity in the period studied (1947-1993). From 1950 to 1960, generation grew at an average annual rate of 8.6%. Strong growth continued into the next decade and generation grew by 7.3% from 1960 to 1970. However, the 1970s signaled the first major trend in a slowdown in electricity generation. From 1970 to 1980, generation grew by only 4.1% annually. This is attributed to the 1973 and 1978 oil crises in the U.S. From 1980 to 1990, electric generation growth was only 2.1% per year. In 1992, generation growth was minus 0.98%.

The slow down in growth is attributed to oil price shocks leading to reduced energy consumption. The Ford, Carter and first Bush administrations also enacted conservation policies. As the economy in the U.S. and other industrial nations matured, economic growth slowed down. In addition, a move away from a manufacturing based economy to a service based economy reduced the derived demand for energy.

4.7.2 Fuel Use in the Electric Utility Industry 1947-1993

A complete review of the history of fuel use, i.e., natural gas, nuclear power, hydroelectric power and oil, in electric utilities is presented by Aabakken (1995). A summary of coal usage is presented here.

Coal has played the largest role in electric utility generation. Due to its abundance and low cost, coal has remained competitive in electricity generation since the birth of the industrial revolution. From 1947, coal increased in generation and maintained a fairly constant share of the total generation in all but a few recession years. In 1947, coal generated a total of 255,739 MWh, which was 53.6% of the total electricity generation capacity at that time. By 1950, coal's share had dropped to 46.9% due to gains in oil and natural gas generation. By the end of the decade, coal generation had more than doubled to 710,000 MWh and provided 53.3% of total electricity production. During the 1960's electric generation by coal again doubled but by 1969 coal generation accounted for only 49% of the total electrical generation. The loss of share reflected mostly gains made by natural gas generation.

During the 1970s, the share of coal generation stayed below 50%, but by 1980 coal again made up half of the electricity generated in the U.S. Coal generation accounted for 2.2 million MWh.

The period from 1980 to 1989 shows a slow, steady growth for coal, and by 1989 the coal market share had increased to 54.6% of the total. This share persisted until 1993, when coal made 56.9% of the total electricity.

The fortunes of coal began to turn when concerns were raised about the emissions of sulfur and nitrous oxides from the burning of coal.

Future threats to coal are taxes that aim to limit carbon dioxide emissions. Any such tax would hurt coal disproportionately, as coal produces relatively more CO_2 per KWh of generation than oil or natural gas. A tax on carbon emissions would, therefore, increase the cost of coal generation more than the cost of gas or oil generation. These possible future liabilities have been among the disincentives to further investments in coal-fired generation plants.

4.7.2.1 Regional Electricity Fuel Use

The choice among fuels for electric generation depended to a large extent on the resources available with the regions. States such as Oregon, Washington, and Idaho that have ample hydroelectric resources, chose to utilize hydroelectric power for the majority of their electricity needs. Oil generation was relatively low until 1966 and then increased rapidly. However, oil generation was concentrated among costal states that had sea access for imported oil. After the 1970s oil crises, oil lost favor, and generation fell rapidly in both absolute and relative terms.

Natural gas was concentrated in the largest gas-producing states in the West South Central region. Shortages due to regulatory constraints made gas less attractive after the 1970s, especially for states outside the producing region.

Nuclear generation grew rapidly in the 1970s and 1980s. Most of the nuclear generation capacity was installed in the Eastern and Midwestern Regions, where demand for electricity was greatest.

Coal use was largely concentrated in the East in 1947, and as Western coal producers emerged, coal found new markets and quickly gained generation share where access to inexpensive coal was possible. This process is particularly visible in the Mountain and West South Central regions where coal production initially was limited. Overall, coal comprised roughly half of electricity generation throughout the period covered.

The New England Region rapidly developed during the Industrial Revolution and by 1947 was dependent upon coal for half of its electricity. This remained until 1966 when oil drastically took market share from coal and nuclear power began to emerge. By 1978, coal's share was down to 2.5% of electrical generation. In the 1980s, coal regained part of the share from oil. Nuclear power continued to grow and gas began to emerge as a power utility fuel. In 1993, nuclear made up 52.8% of the total electrical generation, oil 20.7%, and coal 17.9%.

The heavily industrialized Middle Atlantic Region (Pennsylvania, New Jersey and New York) relied heavily on coal for the majority of its electricity production in 1947 (77.5%). The remaining electrical generation came from oil and hydroelectric, 4.2 and 18.2%, respectively. In 1966, nuclear and oil began to replace some of coal's share of the electrical market. Nuclear grew rapidly until 1993 and there were significant variations in the share of electrical generation by nuclear fuel within the region. Electrical generation by nuclear in Pennsylvania, New Jersey, and New York was 35.7, 72.7, and 25.3%, respectively. Oil rose to a peak of 34.6% in 1973 declining to 6.5% in 1993. Gas had declined to almost nothing by 1978 but made a return and made up 7.5% in 1993. Hydro declined to 9.1% in 1993.

The East North Central Region (Illinois, Indiana, Michigan, Ohio, and Wisconsin) generated almost all its electricity by coal in 1947. Up to 1970, coal's share remained constant while gas made up some of hydro's share and nuclear began to become important in the area. Oil began to capture some of coal's market share in the late 1960s. By 1980, nuclear power made up 14.1% of total generation. By 1993, coal and nuclear were responsible for 73.3 and 25%, respectively, of the total electrical generation capacity. There is wide variation in the nuclear generating capacity in the region.

The West North Central Region (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota) had a well-diversified mix of fuels for electricity generation in 1947. Coal made up 46.4%, oil 11.1%, gas 24.8% and hydro 17.6% of total electric utility generation. In 1960, coal began to capture market share at the expense of gas as western coal producers increased access to coal. Nuclear just emerged on the market and grew rapidly to 10% in 1974. During the 1980s, coal and nuclear continued to gain market share while the other fuels declined. In 1993, coal generated 75.9%, nuclear 17.5% and hydro 4.4% of the total market.

In 1947, coal made up more than half of the market in the South Atlantic Region (Delaware, District of Columbia, Florida, Georgia, Maryland, North and South Carolina, Virginia, and West Virginia). Hydroelectric made up one third of the market at that time. In 1967, oil began a growth period along with nuclear power. Nuclear power increased until 1993 when it was responsible for 27.5% market share. Oil peaked with a share of 26.3% in 1974 and then declined until it was at 7.5% in 1993. The region had extreme variations in fuel use. For example, Washington, D.C. had 99% coal generation from 1947 to 1966 then a rapid fall to zero percent in 1976 through 1992. Oil replaced coal and had 100% of the market share by 1976 through 1993. By contrast, coal makes up 95% of the market share in West Virginia. Nuclear power generation in Virginia peaked in 1985 at 53% and was at 43.5% in 1993. Nuclear power accounts for 61.1% of the market in South Caroline and 44.2% in Florida.

The East South Central Region (Alabama, Kentucky, Mississippi, and Tennessee) depended on hydroelectric power for over 80% of its electricity in 1947. Gas and coal made up 6.6 and 26.9% of the market share, respectively. By 1960, coal produced 74.5% of the electricity while hydroelectric has decreased to 20%. These share remained constant until the 1970s when oil began to take up a portion of the market share. However, the market share by oil vanished by the 1980s. Nuclear emerged in the 1990s and made up 10.6% of the market share by 1993. The delay of nuclear power in the region was due to the ongoing problems by the Tennessee Valley Authority to get their reactors online.

The West South Central Region (Arkansas, Louisiana, Oklahoma, and Texas) was dependent upon gas for the majority (86.8%) of its electrical generation in 1947. This is due to the vast gas resources in the region. It was not until 1970 that coal, oil and nuclear use began to increase. Production of lignite in Texas made inexpensive coal available and Arkansas built four large coal power plants in the early 1980s. By 1993, coal, gas and nuclear were responsible for 49.4, 37.1, and 10.2% of the market share, respectively.

The Mountain Region (Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming) relied heavily upon hydroelectric power (79.9%). Coal and oil combined accounted for 10% and gas made up the other 10% of the market. Coal use began to increase in 1960. By 1975, coal was responsible for half the electricity in the region. By 1993, coal made up 75.9% of the market and nuclear accounted for 8.6% of the electrical generation. Arizona and Colorado both had nuclear power. Nuclear power peaked in 1981 at 2.8%. The plant was shut down in 1990. Nuclear power generation peaked in Arizona in 1988 at 37.3% share. In 1993, nuclear accounted for 32.4% of the market in Arizona.

The Pacific Region (California, Oregon, and Washington) generated 75.9% of its electricity with hydro in 1947. Oil generated 16.7% while gas made up 6.6% of the market share. From 1970 to 1978, oil grew rapidly at the expense of hydro and gas but shrank rapidly to less than 2% by 1984. By 1992, nuclear power generated 18.6% of the electricity. Coal emerged into the market and accounted for 4.9% in 1993. Hydro still holds a share of 56.3% in the region. Hydro had a share of 99% through 1964 in Washington and Oregon. In Washington and Oregon, coal generation accounts for 10.5% in 1993. In 1993, nuclear power accounted for 8.5% in Washington and 0% in Oregon.

By contrast, nuclear power accounts for 25.1% of the market share in California. Coal use was nonexistent and oil had roughly 20% of the market until 1961. Oil use peaked in 1977 at 55.7%. In 1993, oil only accounted for 0.8% of the market share. Natural gas made up the market lost by oil and made up 37% of the market share in 1993. Hydroelectric power accounted for 30.3% of the market in California in 1993.

A further detailed discussion of the history of regional coal use in the U.S. is presented in Aabakken (1995).

4.7.3 Coal Consumption In Electric Utilities 1947 to 1993

The focus of this discussion is the use of coal in electric utilities since coal has been the single largest fuel source for electric generation since 1947. Coal generating power plants have provided roughly half the electricity produced by electric utilities in the U.S. Coal is the least cost fuel for electricity generation, however, new environmental regulations threaten to increase capital and operating costs.

Coal generation was concentrated in the Eastern and Midwestern states where coal resources were abundant. In the 1970s, Western coal producers emerged and coal increased in its generation share in those states. Within the U.S., the market share of coal for electric generation varies significantly as a function of regional natural resources and state environment regulations.

In 1947, coal generated 136,985 MWh of energy or 53.6% of total generation of utility electricity. A decade later coal generation was 631,507 MWh or an increase of 360% or a market share of 54.9%. In 1977, the coal share of generation had fallen to 46.4% but its generation in absolute terms had grown to 2,124,323 MWh (roughly double the generation of the previous decade). In 1987, coal generated 2,572,127 MWh, and increase of only 20.1% from the previous decade. This slowdown in increase coal consumption coincides with the 1973 and 1978 oil crisis and the overall reduction in the growth of electrical consumption. By 1990, coal's market share was 54.9% increasing slightly to 56.9% in 1993.

Coal's market share in electric generation has remained fairly constant (approximately 50%) since 1947; however, there have been significant regional variations in coal use during that time. The most marked development is the growth of western consumption of coal. In 1947, coal only accounted for 10% (8,297 MWh) of the electricity consumed in the Western U.S. In contrast, coal accounted for 73% (136,985 MWh) of the electricity consumed in the Eastern U.S. A decade later western coal generation had nearly doubled to 14,265 MWh, while in relative terns coal generation had fallen to 7% of total generation. In the East, coal generation had nearly tripled to 332,120 MWh with the share of coal generation increasing to 78%.

In the 1970s, coal experienced a rapid growth in the West. Generation grew to 216,287 MWh corresponding to a market share of 26%. The East also saw a rapid growth in total generation 768,930 MWh but this corresponds to a drop in market share to 58% (from 78% in the 1950's). In the 1980s, coal use in electrical generation increased in both absolute and relative terms in both the West and East. By 1993, the market share by coal in electricity generation in the East and West had increased to 61.2 (1,019,751 MWh) and 50.2% (556,145 MWh), respectively. A detailed discussion of the regional coal use for electricity generation is presented by Aabakken (1995).

4.7.4 Trends in Coal Consuming Electric Utilities

Tables 4.7.1 and 4.7.2 list the 25 largest coal consuming utilities in 1969 and 1993. The physical receipts of coal to these utilities are used as a proxy for actual consumption in 1993. Aabakken (1995) gives additional data covering the years 1979 and 1989. The general trend is that the role of the "large consumers" has reduced with time. The percent of utility coal receipts accounted for by "large consumers" has decreased from three-quarters to one-half. This reflects the spread of coal use into regions where coal was previously not used for electricity generation.

4.7.5 Historical Patterns in Electric Utility Power Plant Additions, Developments 1947-1993

Capacity additions were growing until 1974 at a rate of 7% per year, after which, a general downward trend was observed. This is attributed to the 1974 oil crisis, which resulted in increased energy prices and a decrease in consumer demand. The basic pattern of capacity additions between 1947 and 1993 follow an inverted parabola. There were low levels of capacity additions in 1947 followed by a gradual increase. A peak was reach in 1974 in absolute terms.

In 1992, only 3,886 MW of new units were added. This is less than the 4,349 MW added in 1949 and is only a fraction of the 40,727 MW added at the peak in 1974. Only six years after the peak, capacity additions were roughly halved. The 1989 additions marked the first time since 1957 that additions were less than 10,000 MW. Coal, oil and gas are discussed in the following sections. More detailed discussion regarding these fuels, hydroelectric and nuclear power are given in Aabakken (1995).

Table 4.7.1 1969 Top 25 Coal Consumers 25 Largest Coal Consuming Utilities, 1969

Company	Thousand Tons	Percent of Total	Cumulative Percent of Total
Tennessee Valley Authority	30,890	9.95%	9.95%
American Electric Power Co.*	30,802	9.93%	19.88%
Commonwealth Edison Co.	18,905	6.09%	25.97%
The Southern Co.	17,409	5.61%	31.58%
Ohio Edison Co.	12,914	4.16%	35.74%
Duke Power Co.	11,845	3.82%	39.56%
Detroit Edison Co.	11,745	3.78%	43.35%
Centerior*	11,429	3.68%	47.03%
General Public Utilities	9,901	3.19%	50.22%
Allegheny Power Systems, Inc.	8,979	2.89%	53.11%
Consumers Power Co.	6,557	2.11%	55.23%
Virginia Electric & Power Co.	6,449	2.08%	57.31%
Carolina Power & Light Co.	5,880	1.89%	59.20%
Wisconsin Electric Power Co.	5.038	1.62%	60.82%
Public Service Co. of Indiana	5,008	1.61%	62.44%
Niagara Mohawk Power Corp.	4,712	1.52%	63.96%
Potomac Electric Power Co.	4,425	1.43%	65.38%
Duquesne Light Co.	4,230	1.36%	66.75%
Consolidated Edison Co.	3,754	1.21%	67.95%
Cincinnati Gas & Electric Co.	3,575	1.15%	69.11%
Electric Energy Inc.	3,511	1.13%	70.24%
Baltimore Gas & Electric Co.	3,451	1.11%	71.35%
Northern States Power Co.	3,402	1.10%	72.45%
Arizona Public Service Co.	3,175	1.02%	73.47%
Philadelphia Electric Co.	3,120	1.01%	74.48%
Total Above	231,106	74.48%	
Total Utility Receipts	310,312		

*As defined by its 1993 components

Sources: Details from National Coal Association, *Steam Electric Plant Factors,* 1970. Total from Edison Electric Institute, *Statistical Yearbook,* 1970, as compiled in Richard L. Gordon, *U.S. Coal and the Electric Power Industry,* 1975.

Table 4.7.2 1993 Top 25 Coal Consumers 25 Largest Coal Consuming Utilities, 1993

Company	Thousand Tons	Percent of Total	Cumulative Percent of Total
Southern Company	46,970	6.11%	6.11%
AEP owned or managed	46,770	6.08%	12.19%
Tennessee Valley Authority	40,387	5.25%	17.44%
Texas Utilities	31,462	4.09%	21.53%
Pacificorp	29,687	3.86%	25.39%
Detroit Edison	18,261	2.37%	27.76%
Houston Lighting and Power	18,056	2.35%	30.11%
Central and Southwest	17,995	2.34%	32.45%
General Public Utilities	15,659	2.04%	34.49%
Basin Electric Cooperative	14,963	1.95%	36.43%
Allegheny Power System	14,048	1.83%	38.26%
Ohio Edison Total	13,506	1.76%	40.01%
Arizona Public Service	12,243	1.59%	41.61%
Northern States Power	12,012	1.56%	43.17%
Duke Power	11,953	1.55%	44.72%
Public Service Co. Indiana	11,461	1.49%	46.21%
Middle South Utilities	11,164	1.45%	47.66%
Commonwealth Edison, Total	10,596	1.38%	49.04%
Virginia Electric and Power	10,277	1.34%	50.38%
Salt River Project	10,176	1.32%	51.70%
Carolina Power and Light	9,840	1.28%	52.98%
Kansas City Power and Light	9,622	1.25%	54.23%
Cincinnati Gas and Electric	8,865	1.15%	55.38%
Western Energy	8,863	1.15%	56.53%
Public Service Co. Colorado	8,788	1.14%	57.68%
Total Above	443,624	57.68%	
Total Utility Receipts	769,152		

Source: U.S. Government, Energy Information Administration: *Cost and Quality of Fuels for Electric Utilities* 1994.

4.7.5.1 Coal Capacity Additions

The slowdown in coal capacity additions is attributed to the slowdown in total electrical generation growth and the impact of environmental regulations specifically aimed at coal-fired power plants. The slowdown in electrical generation growth reflected increasing fuel prices and the subsequent increase in conservation measures. Also important is the fact that there was excess capacity in some areas where growth was slow. The economics of scale is also important. Coal has traditionally been dependent on a relatively large scale of operation to be competitive. Even as the coal itself is relatively inexpensive compared with other fuels, it is voluminous and to get economies of scale a relatively large plant is necessary. The average size of a coal-burning unit seemed to increase up to 1971. This indicates that the optimum scale of a coal plant has changed over time. The economies of scale for coal units seem to be exhausted at roughly 600 MW (Joskow 1987). Interestingly, the average size in 1988, 1990, and 1992 were 300 MW or less.

The heating value of coal has been declining in general since 1960 (Joskow 1987). At the same time the average size of coal plant was increasing. This reflects the increased use of Western coals that have lower heating value than Eastern coals. Longer construction time results in higher capital costs from interest expenses and also exposes that electricity generator to greater risks associated with demand growth, fuel prices and regulatory changes (Dowlatabadi 1991).

Coal capacity additions reached its peak in absolute terms in 1973 when 16,440 MW of coal units were added. Coal reached its peak in market share of 81.2% in 1982. No coal plants were added in 1993 and none were planned through 1995.

4.7.5.2 Oil Capacity Additions

In 1947, oil was a large part of new unit additions (46%). However, by 1954, oil only accounted for 6.6% of new units. Oil became attractive as a fuel after 1966 when the import quotas on residual fuel oil were removed. This led to an increase in the use of oil in the electric power industry. In 1967, 11% of capacity additions were from oil. In 1975, a peak of 20.9% of new capacity was from oil. After 1978 OPEC oil crisis, oil lost favor as a fuel. In 1980, only 6% of the added capacity was oil generated. The low point was in 1984 when oil additions were only 0.2% of the total.

4.7.5.3 Natural Gas Capacity Additions

Natural gas made up 29% of added units in 1947. Additions for gas were generally above 20% until 1973. A slowdown in gas additions in the 1970s was attributed to shortages and the 1978 Fuel Use Act that made it illegal to expand further into gas generation. By 1980, there was little gas capacity being added. Deregulation in the 1980s made gas more attractive. Natural gas combined cycle gas turbines have led to a movement of smaller scale units. The advantage of smaller scale units is their increased thermal efficiency. Two or more units operating a maximum capacity offer better thermal efficiency than a partially loaded larger unit. By 1987, gas accounted for only 0.46% of additions, however, by 1993, 49.4% of additions were from gas.

4.7.6 Market Structure and Reorganization of the U.S. Electric Utility Industry

The electric utility industry is unique in its economic considerations due to its organizational structure, related regulation problems, and the extreme capital intensity. Technically this results from technical diversity and complexity, the promise of emerging new technologies and environmental problems caused by traditional technologies. Politically, this is due to a long complex history of government involvement.

The electric utility industry has undergone significant changes in recent years: regulatory constraints have been reduced, new entities have been created and new technologies have been developed. From an economic standpoint these changes are heading toward market competition and efficiency improvement. However, there is no consensus of opinion regarding the manner in which the industry needs to restructure.

Restructuring the electric utility industry is an economic problem that cannot be separated from political and technological constraints. In fact, economic efficiency and equity-oriented political concerns seem to be in conflict. Many differences between the existing proposals lie in the efficiency-versus-equity dilemma.

The intent of this study is to consider economic, political and technological factors as compatible when evaluating a proposed model with the goal to improve economic efficiency. To achieve this objective the following topics were researched: the status quo of the electric utility industry; analyze the merits and deficiencies of existing restructuring proposals; and factors to be considered for any restructuring approach. This all leads up to a new proposal for restructuring of the electric utility industry. The new proposal is based on the premise that the transmission sector can become competitive. By eliminating the practice of exclusive franchising, transmission competition can occur automatically. With this breakthrough, changes such as divestiture and reorganization can occur as guided by market forces. As a result, both the generation and transmission sector will become competitive and regulation will become unnecessary. Regulation in the distribution sector may not be completely excluded.

The following discussion is a summary of a unpublished doctorate thesis by Li (1995) titled "Market Structure and Reorganization of the U.S. Electric Utility Industry: A New Proposal."

4.7.6.1 Status Quo of the Electric Utility Industry

This section describes the U.S. electric utility industry in the 1990s. The status quo of the industry is the result of a century-long evolution which has been heavily affected by regulations. The rate of return (ROR) regulation, established at the very beginning of this industry, is one of the most important in shaping the industry. In 1935, the Public Utility Holding Company Act (PUCHA), together with other regulations, was enacted to reinforce ROR regulation by confining organizational structures for investor-owned electric utilities.

The deregulation process started in 1978 when the Public Utility Regulatory Policies Act (PURPA) was enacted. In 1992, the Energy Policies Act (EPACT), a deregulation effort, was passed to reduce regulatory constraints. Many other regulations, such as the Clean Air Acts and their amendments, affected the electric utility industry. A detailed review of the organizational structure of the electric utility industry, the regulations that shaped the industrial structure, PUCHA and ROR are presented in Li (1995).

Organizational Structure

A summary of utilities by ownership is given in Table 4.7.3. Sales to ultimate consumers are by investor-owned utilities (IOUs) account for more than 75% of total sales in terms of either dollars or megawatt hours (MWh). In terms of sales for resale, investor owned utilities count for only over 40% (23% of their sales to ultimate customers in MWh). The role of Federal power in the retail market is negligible. The sales for resale of Federal, cooperative, and other publicly owned utilities are similar in either terms of dollars, MWh or percentage. In terms of either sales to ultimate consumers or sales for resale, cooperatives and non-Federal publicly owned utilities have similar importance.

The organizational structure of investor-owned utilities is defined by PUCHA. Each utility has an integrated franchised service area and no utilities have overlapped service territories. Utilities are responsible for providing services to their franchised territories. In return they get regulated prices for their services. Since there is no common market there is little competition between utilities.

Publicly-owned utilities are non-profit entities organized as government agencies. More than 70% of these municipal utilities rely on others, mainly Federally-owned and partially investor-owned utilities, to supply bulk electricity for resale (U.S. Department of Energy, 1993d). Municipal utilities usually have lower rates than investor owned utilities due to favorable regulations, access to lower capital cost and exemption from paying taxes or dividends. They also have preferential access to electric energy produced at Federal facilities. Economists from an efficiency perspective have criticized publicly-owned utilities since none of these advantages are based upon market competition. The largest publicly-owned utilities are similar in size to the typical investor-owned utility. Sales to ultimate consumers by a typical publicly-owned utility are only 196,037 MWh or approximately only 2% that of the typical investor-owned utility.

Cooperatives were established in 1935 via the Rural Electrification Administration (REA). Legislation provided low interest loans for the construction of rural transmission and distribution networks. The cooperatives were formed to take advantage of this low cost financing by building facilities necessary to move purchased

Table 4.7.3 Selected Electric Utility Data by Ownership, 1991[1]

	Investor-Owned	Publicly Owned	Federal	Cooperative	Total
Number of Electric Utilities	265	2,007	10	949	3,231
Electric Utilities (Percent)	8.2	62.1	0.003	29.4	100.0
Revenue from Sales to Ultimate Consumers (Thousand Dollars)	147,587,609	23,151,761	1,479,079	14,147,154	186,360,603
Revenue from Sales to Ultimate Consumers (Percent)	79.2	12.4	.8	7.6	100.0
Sales of Electricity to Ultimate Consumers (Thousand Megawatthours)t)	2,110,528	393,448	52,943	205,082	2,762,003
Sales of Electricity to Ultimate Consumers (Percent)	76.4	14.3	1.9	7.4	100.0
Revenue from Sales to Resale (Thousand Dollars)	17,459,163	7,308,471	6,341,529	9,784,621	40,893,784
Revenue from Sales to Resale (Percent)	42.7	17.9	15.5	23.9	100.0
Sales of Electricity Available for Resale (Thousand Megawatthours)	487,094	193,273	200,666	235,620	1,116,654
Sales of Electricity Abailable for Resale (Percent)	43.6	17.3	18.0	21.1	100.0

Source: U.S. Department of Energy, 1992. *Financial Statistics of Major Investor-Owned Electric Utilities,* 1991.

[1] This table overstates the number of independent private companies by including every entity that regulators treat as a separate unit. Several forms of subsidiary relationships prevail. The first is the holding company form discussed more fully below in which a single nonoperating corporation owns two or more operating subsidiaries. Alternatively, one operating company may have one or more operating subsidiaries. Independent companies may jointly own other companies. Several nuclear plants in New England and three coal-fired plants in the Middle West were built as separately incorporated joint ventures. Once all these relationships are considered, the number of large independent investor-owned companies is under 100.

electricity to rural customers. Cooperatives are owned by their customers and are non-profit and pay no taxes. The average sale of a cooperative is 222,531 MWh and the average number of customers is 12,889 (Table 4.7.3).

The dominant activity for Federally-owned power organizations is the sales for resale. Due to subsidies, the rate from Federally-owned powers is lower than that from investor-owned utilities. The Tennessee Valley Authority (TVA) and the Bonneville Power Administration (BPA) are the largest Federal entities. 1n 1990, the TVA and BPA accounted for 49 and 29%, respectively, of the total sales for resale (195,674 KWhs) by Federal electric utilities (U.S. Department of Energy 1992).

The TVA was created in 1933 primarily as a navigation and flood control project with hydro electrical power generation as a by-product. However the generation of electric power has become the main purpose of the TVA. In addition, the majoring of the power is generated via steam (fossil fuels and nuclear). The success of the TVA is disputed due to problems associated with pollution and environmental impacts and the expense and difficulties in managing nuclear power plants.

Given the demographics of electric power generation, the focus of restructuring will be on the dominant investor-owned utility sector. A detailed discussion of the following can be found in Li (1995): PUHCA and investor-owned utilities; ROR regulation; the Public Utility Regulatory Policies Act; the Energy Policy Act; mergers, power pools and larger scale cooperation; and research and development activities.

4.7.6.2 Existing Proposals for Restructuring Total Deregulation

Advocacy of regulation is based upon the belief that the electric utility industry is a natural monopoly since only one firm is needed to serve an area. The purpose of regulation, in theory, is to mimic the result of what a competitive market would produce. However, Demstez (1968) states that the asserted relationship between market concentration and competition can not be derived from existing theoretical considerations, and the fact that only one firm serves each market does not mean monopoly prices will be charged. Because competition exists to win a franchise and the principal has the option to grant the franchise to another firm at the end of each contract period, Densetz believes that the rivalry of the open market place disciplines more effectively than do the regulatory processes of public utility commissions.

To promote competition, Demsetz advocates public ownership of distribution facilities, and then private firms would bid for the right to operate these facilities. Given the capability of long distance transmission, many firms can serve any area and any firm can serve many areas.

Posner's (1969) conclusion is similar to Demsetz, however, Posner believes that it is plausible to assume that an unregulated monopolist will typically set prices and obtain profits that are excessive. Posner realizes the importance of technological developments. Posner argues that society should not be deeply concerned if a natural monopolist charges an excessive price. "Regulation is assumed by nearly all who work or write in the field, as by the public in general, to be fundamentally inevitable, wise, and necessary. However, ... public utility regulation is probably not a useful exertion of governmental powers; that its benefits cannot be shown to overweight it costs; and that even in markets where efficiency dictates monopoly we might do better to allow natural economic forces to determine business conduct and performance subject only to the constraints of antitrust policy (Posner 1969, p. 549)."

Gordon (1982, 1990) states that generation probably is not a natural monopoly and should not be regulated. He argues that regulatory improvements in this sector is unlikely and stresses regulatory reform over restructuring. According to Gordon, the present structure of the electric power industry is far from optimal and the need for reorganization of the operating firms is a key reason for eliminating regulation. The key problem comes from the under-pricing of electricity.

Gordon believes in interfuel competition and trusts more the strength of interfuel competition than the effectiveness of regulation. He favors Weiss's (1975) proposal to increase competition by the breaking up of combined electric and gas companies. Gordon recommends the following changes to correct inefficiencies in the electric utility industry: increase the number of participants; allow participants' access to a larger number of customers; and allow more flexible pricing (Gordon 1990).

Full Regulation

A total deregulatory approach is based upon economic principal while the full regulatory advocate is based upon consideration of daily practice. Criticism of Demsetz's contract approach is given by Williamson (1976). Williamson states that the difficulties of specifying a long-term contract with uncertainties included lead to the contracting approach converging to regulation. Therefore, the competition of bidding to win a franchising contract is not enough to replace regulation.

Marshall (1982) feels that the nuts and bolts of industry have not received enough attention and that too much attention has been placed on broad economic theories. Marshall fees that the theories fail to recognize the forces and effects of the traditional responsibility of a utility to provide services. He is arguing that without regulation electric utility markets will not satisfy the economic definition of well-functioning markets. Market stability is also a requirement. Marshall also feels that it is impossible to separate the generation, transmission, and distribution sectors, and treat the transmission sector as a common carrier.

David and Burton (1982) feel that the electric utility industry cannot be vertically disintegrated on a purely voluntary basis. They seek solution by modifying the existing regulations instead of changing the organizational structure of the industry. Bushnell (1990) states that none of the failures of regulation, the failures of deregulation, the promotion of bypass and the profit motivation from Wall Street provide compelling reasons for restructuring. Bushnell considers the "path to restructuring and competition to be somewhat perilous (Bushnell 1990, p. 593)" due to the concerns of reliability, equity, obligations to serve and the risk of being wrong. As long as economic power is concentrated, the potential for monopoly abuse will persist (Bushnell 1990). There is also concern regarding equity. There is a risk that a two-class society will develop as market forces (geographic and demographic disparities) are not equal in rural and metropolitan areas. Bushnell suggests the use of inefficient cross subsidies to solve the equity issue. While it is well known that regulation is not the best way to promote equity and that cross subsidy makes utilities vulnerable, it may not be practical to ignore the equity issues.

Weiss's Proposal

According to Weiss (1975), the economics of vertical integration between generation-transmission companies and distribution firms seems unlikely. Competition should be favored as the benefit of competition outweighs the cost it incurs. To promote competition, Weiss proposes the separation of generation-transmission companies from distribution companies, while at the same time maintaining the integration of generation and transmission systems. The generation sector will be governed by competition, including sales to distributors and large industrial customers, as well as bulk power sales. With regards to transmission, monopoly power still exists and the necessity of regulation is justified. Transmission should become a common carrier and the function of regulation is to guarantee proper interconnections and wheeling charges. Weiss does not see much potential for competition in the transmission part but recognizes its important role.

Weiss also proposes the dissolution of combination utilities that own both gas and electric business to increase competition. This proposal has been supported by Gordon (1990).

Cohen's Model

Cohen's (1979) model is to rely on Congress to enact legislation to provide for the chartering of regional bulk-power dispatching corporations (RDCs). "Each such corporation would be directed to acquire all of the high-voltage transmission capacity within its region, to lease generating plants from producers and to dispatch electricity for resale to independent distribution companies. Utilities would continue to own generating plants and/or distribution systems, but the authority to dispatch bulk power facilities to transmit electricity at high voltage, and to sell bulk power at wholesale would be vested exclusively in the RDC (Cohen 1979, p. 1539)."

"Each RDC would be an investor-owned corporation, run by share-holders for their own benefit, subject to statutory restrictions. Diversification would be forbidden and RDCs would be required to serve all distributors in the region. Each RDC would enjoy a monopoly over transmission in its region. The sacrifice of competition at the transmission stage is a necessary concession to the physical properties of electric power, which made transmission a natural monopoly. Thus that part of the industry would continue to require rate regulation, ... (Cohen 1979, p. 1540-1541)."

The advantages of the new structure are as follows: 1) the new structure would create a regional bulk power system large enough to capture all feasible economies of scale; 2) competition is enhanced and innovation would be spurred; 3) RDCs would have no incentive to discriminate against any producer or ay type of technology; 4) competition would be increased at the distribution stage; and 5) disparity would be eliminated by charging the same rates for bulk power throughout the region.

Cohen acknowledges some problems with the new structure. The rate of return regulation could encourage RDCs to over invest in the transmission grid. The reliability of electricity supply would be affected and there could be an effect on long-term planning and development of new power plants. Given the long lead time, the huge investment, and many unforeseen factors, Cohen acknowledges that no prudent firm would bind itself to deliver capacity from a new plant at a specified price with out first running the regulatory gamut.

Berry's Model

According to Berry's Model (Berry 1982), the current vertically-integrated system would be replaced by separating generating and distribution companies linked by energy brokers. The generating companies would be free of regulation, whereas, the brokers and distribution companies would still be regulated. The advantage of the Berry Model is the efficiency gain of increased coordination. Currently there are 152 separate centers controlling the use of the nation's generating capacity (NERC 1992). Berry' model is the only model that addresses the addition of new capacity among all the restructuring proposals. Under Berry's model, the financing and development of new capacity is completely determined by market force. Berry is also the only author who clearly describes alternatives a distribution can have in a competitive environment. Berry envisions a dozen or so electric regions each of which is operated by an energy broker, i.e., a large organization. Berry also proposes the creation of secondary markets and even possibly future markets to trade long-term contacts. He also envisions the need for short-term and spot markets. Weiss's, Cohen's and Berry's models all agree that the generation sector is competitive and the distribution sector needs to be regulated. They differ in how to solve the transmissions problem.

Other models summarized by Li (1995) but not discussed here include: direct competition among integrated utilities as proposed by Primeaux (1975); Houston (1983/84); O'Connor (1985); Joskow and Schmalensee Scenarios (1983); Scenarios of Office of Technology Assessment (Blair 1990); and spot pricing by Schweppe et al. (1988) and Hogan (1993).

Summary

The proposals presented and reviewed by Li (1995) are quite diverse. However, the following considerations are critical to each of the models.

1. Economics of coordination. The potential of efficiency gains by large-scale coordination has not been fully realized. Most authors clearly realize this point and treat it as an important objective of reform. The efficiency gains can be realized by RDCs, energy brokers, regional dispatching or by mergers and power pools, but at the same time these approaches will result in market power concentration. An ideal solution should realize the efficiency gains from large-scale coordination and at the same time avoid market power concentration.

2. Reliability. Most proposals consider this factor explicitly. Maintaining reliability is costly and the optimal level changes with the distribution area. Maintaining optimal reliability levels for different regions should be one of the objectives of restructuring.

3. Planning. Restructuring the existing industry seems easier than the development of new power plants since the physical assets are already present. However, no proposal can be adequate without addressing the capacity addition problem.

4. Transmission bottleneck. Most proposals realize the decisiveness of the transmission sector to the whole industry. It is clear the organizational structure of the transmission sector will determine if market forces can work.

5. Regulation. Every proposal recognizes the problem of regulation. Most proposals advocate regulation of the distribution sector and deregulation of the generation sector. Solutions to the transmission sector are quite diversified.

Several authors (e.g., Weiss (1975) and Gordon (1982, 1990)), propose the disintegration between transmission and distribution. Houston proposes direct competition at the retail level. However, direct competition for electricity consumption at this level seems unlikely. So the practical competition only happens between transmission and distribution, and between generation and transmission. Another important efficiency concern is whether the industry can accomplish the transition in a timely and efficient way that reduces total cost (production and adjustment costs). The restructuring process itself is also very costly. Therefore any reform can only go forward slowly but provide enough flexibility so future adjustments will occur incrementally and timely in response to any possible future changes.

The overall objective of restructuring is to minimize the total cost of providing electricity services by minimizing the cost of electrical supply and consumption. The objective of the new proposal developed by Li (1995) is to create a competitive environment by solving the transmission bottleneck problem and is summarize below.

4.7.6.3 Factors to be Considered for Restructuring

Factors to be considered for restructuring include the following: status of the existing generation, transmission and distribution system; threshold of transmission and distribution competition; transmission and market structure; market differentiation and competition; reliability and competition; uncertainties; flexibility and equity issues. A detailed discussion regarding how these factors impact restructuring considerations is given in Li (1995).

4.7.6.4 A New Proposal

Technologies of transmission have made it possible for the transmission sector to become competitive. As long as this condition exists, the generation sector will automatically become competitive regardless of its economies of scale. After market differentiation, all retail customers that can be potentially involved by market competition will be included in the transmission competition part. Market competition definitely cannot happen in the remaining distribution sector. Based upon these results, this new restructuring approach focuses on the transmission sector.

Reconfiguring a Transmission Grid

To create alternatives for distribution companies (discos) and minimize the cost of transmission competition, this model proposes breaking up the geographically isolated ownership structure of the existing transmission system. Once this artificial boundary is eliminated, the whole nation becomes the potential service area for each transmission company (transco). By slightly reconfiguring the physical structure and at the same time moderately modifying the existing ownership structure, this system guarantees that each small area can be served by more than one transco. In this way, competition is introduced into the transmission sector and all generating companies (genecos) and discos will have alternative for transmission services. It is argued that the existing lines can enjoy substantial Ricardian efficiency rents due to their superior locations. Since this restructuring approach does not need massive change of the physical transmission system, the total amount of efficiency rents on the existing lines will not be significantly affected. A detailed discussion as to how competition can be introduced into the transmission sector via reconfiguration is given in Li (1995).

Configuration of the Existing Grid

Reconfiguration of the existing transmission structure depends on the density and the geographic layout of the transmission lines. The density of the transmission lines affects competition in many ways. If the density is higher then the cost of a disco's switching from one transco to another will be lower and vice versa. The lower switching cost will intensify transmission competition, and the higher cost will inhibit competition. Secondly, if the density of transmission lines is lower, fewer substations will be needed, which means that the mutual restriction mention in the above section will be weaker. On the other hand, with the lower density of transmission lines, the potential benefit of line extension might be higher. Thirdly, if the density is higher, it will be easier for each transco to form an interconnected independent system. Also it will be easier to have more transcos serving one area.

Given the density of the transmission lines, the actual layout of the transmission lines is another determinant of competition. In addition, the number of lines linked to one node is also important. If several lines are linked to one node, that means a disco located there can get access to several transcos through the node and the competition at that point will be strong. The density and layout of lines varies geographically.

Theoretically, there are an unlimited number of transmission line combinations to form transcos. Therefore, it is impossible to create an exact reconfiguration plant and only some general considerations can be provided. The technology of electricity transmission has already made it possible to form a nationwide competitive transmission market. By reconfiguring the transmission system, large transcos can be formed with each transco serving a very large area, possibly even the entire nation. As a result not many transcos are needed. Due to regional differences in transmission line configuration and electricity demand, the strength of the competitive force will vary geographically. Although it is possible that, for some area, the market competition approach may not be superior to regulation, in general market competition is clearly preferred.

The Cost of Reconfiguration

Physically, the reconfiguration involves only changes in the transmission sector. Due to the involvement of asset reallocation, which includes not only the transmission sector but also the generation and distribution sectors, the cost of reconfiguration involves much more than the incremental cost generated by the physical changes in the transmission system. Since little is know about the asset reallocation, this section only estimates the cost resulting from the physical changes in the transmission sector.

From 1987 to 1991, the total structure miles of transmission line changed 719, -1,656, 3,568 and 4,167 miles per year, respectively (this represents a change of 0.2, -0.5, 1.0. and 1.2% of transmission line addition respectively). Assuming the transmission system extends 10% due to the restructuring, then it requires at least $5.5 billion dollars of new investment. This represents only about 1% of the $476.6 billion dollars in total assets of the entire system in 1991. This 10% extension only accounts for 3% the total revenue in 1991 of $167 billion dollars. It should be mentioned that an increase cost of communication would occur with reconfiguration due to the larger service area.

There are also effects on the organizational structure. In general, the new structure is highly flexible. The reconfiguration only requires breaking up the geographical concentration of transmission ownership. No other structural restrictions are imposed. The critical issue of restructuring is whether the benefit of vertical disintegration between generation and transmission outweighs the related cost. For this restructuring proposal, the answer for this issue is left to the market. If the benefit of integration is bigger then vertical integration will prevail. Otherwise a disintegrated structure will result. It is quite likely that for some of the power plants the benefit of vertical integration is greater while for others the benefit of disintegration is greater.

Another organizational alternative is a contract arrangement. The organizational structure can also be affected by population density. Further details are discussed in detail by Li (1995).

Capacity Addition

If the financial market is reasonably efficient then investment can always be financed as long as returns compensate for related risks. The question is whether the restructuring makes the risk of new power plants so high that the cost of power plant financing becomes so expensive that the price of electricity becomes too high to be acceptable. Investment can be divided into two parts: systematic risk and investment risk of each individual power plant. Systematic risk defines the overall average risk of investment. It is affected by many factors, e.g., the overall future economic development, future electricity demand, future fuel prices, environmental regulation, and technological progress. The accuracy of forecasting these variables depends on three factors: quality of input information for forecasting; capability of forecasting models; and the future time interval of forecasting. The data quality used for forecasting is not going to change with the structural change. The forecasting model will not be improved by structural change. With the structural change the regulatory processes for power plant investment will be simplified. As a result, the lead-time of plant construction will be shortened. The reduced time interval of forecasting will increase the accuracy of forecasting.

Resistance to restructuring includes concerns about who pays for what are termed ‘stranded’ investments. These are the investments by utility and nonutility investors in facilities that cannot compete in a deregulated environment. Critics of deregulation express concerns that customers (residential and commercial) will bear an excess share of the burden of covering these costs. The argument assumes that whatever control mechanism is in place will allow utilities significantly to increase rates to these inflexible customers.

Capacity addition can take three forms: vertical integration; contract arrangement; and independent initiatives. For each individual power plant, the investment risk depends on final demand uncertainties. Since the demand from different discos is independent, the more discos are involved, the lower the variance of the final demand. Under the new system, a transco can cover a much larger geographic area and link many more discos together. Electricity generated by the integrated power plant can be sold through the whole transco system. If one disco has lower than forecast demand, another disco might have demand higher than forecast. As a result, the demand uncertainties may be lower under the new system than under the current system. Under the new system, no demand guarantee is given to the discos. However, the demand discos face comes from final consumer. No guarantee from the final consumers exists under the current or new system.

For contract agreements, a new genco needs only to contract with a transco directly and does not have to rely on one transco to provide transmission services. In addition, the genco does not need a contract that covers the whole life of a new power plant. Depending upon a geneco's capability and willingness to take risk, a contract can be just long enough to reduce the investment risk to the geneco's acceptable level. As a result, contract arrangements will be easier and the transaction cost of contracting will be reduced. Further discussion relating to contract arrangements between genecos and transcos and independent initiatives is given by Li (1995).

Each of these alternatives has advantages and disadvantages. The one that is most appealing can only be determined by specific circumstances. In general, it might be expected that larger plants would be inclined towards vertical integration and smaller plants would encourage independent initiatives. A larger plant requires a greater amount of investment, requires a longer lead time and involves more uncertainties; therefore, a vertical integration approach for adding capacity would minimize risk.

For the new system, the justification for new capacity addition is market demand. As with the current system, this is no guarantee for return, however, under the new system the variance of return on power plant investments is widened. In general, the total societal risk of restructuring will not increase but the way that risk is allocated will change.

The cost of investment is also related to the size of the firm that will own a new power plant. If the amount of investment is too large then a small firm may find it too difficult to handle. Under the new structure the geographic concentration of transmission lines will not exist and the number of genecos can also be greatly reduced from the present level. Even if there are only ten generation firms they will compete in every region. In essence, each region will have ten competing genecos that may make the market force work reasonably well. The effect of PURPA and EPACT and independent power production on added capacity is discussed in detail by Li (1995).

Regulation

With the new structure, the generation and transmission sectors will be very competitive such that no franchising and rate of return regulations are necessary. With the competition among transcos, besides line extension and modification there can also be some exchanges of existing transmission lines, even after the restructuring is completed. So antitrust scrutiny might be needed. For the distribution sector, regulation may still be needed depending on the structure of each disco. If a disco is independent, then only retail rates may need to be regulated. If a subsidiary of a company that owns a transco, regulation may be need to make sure that the transco does not get any offer from its own disco that excludes other transcos based upon noncompetitive factors. This integrated structure is similar to the current structure. The difference is under the new system each firm has more choices as to how they operate.

If a firm owns several genecos and discos together with a transco, the same regulatory approach applies as the firm makes a special arrangement with a transco to transmit electricity from its own genecos to its own discos. The same regulatory approach may be needed to guarantee that the geneco does not get any special treatment. If the firm own genecos and discos but no special arrangement is made between them and all transactions are based upon competition, then no other regulation is needed besides rate of return regulation on the disco.

Given the potential of improving efficiency on the demand side, discos may also want to take measures to improve the efficiency of electricity consumption. The new structure does not propose universal elimination of regulation. The assumption is that whether regulation is inferior to competition depends on how strong the competitive force is and which of the two approaches is more efficient cannot be resolved by theoretical debate. The new structure is designed to provide an opportunity for these two approaches to compete.

Another related issue is whether the responsibility for regulation might be decentralized or centralized. Each municipality might decide to regulate its local discos. The advantage would be greater familiarity with local situations. The drawbacks include the possible losses of economies of scale and the danger that regulation would be even more politicized than under state commissions.

If the government wants to participate in the electric utility industry for the purpose of equity considerations, it only needs to do so through discos. Subsidized discos can go out to shop for the cheapest electricity supplier. Since no regulatory distortion exists in the generation and transmission sectors, government involvement would not result in inefficiency in these two sectors. Only the distribution sector would be distorted by government interference. The restructuring model presented here does not advocate government participation for equity purposes.

How to Get There

To bring market competition into this industry requires the break up of the geographical concentration of existing transmission line ownership. This can be achieved by completely relying on market force. As long as the exclusive franchising is eliminated, transmission competition can arise automatically among neighboring utilities along their boundaries. The primary targets at the initial stage for this kind of competition would be large industrial and commercial customers currently located along a utility border but in a neighbor utility's territory. To attract these customers, utilities would need to extend their transmission lines into each other's territory.

Given the existing integrated ownership structure, it would be very common for a firm to initially own a transco and several genecos and discos. Although the transmission line extension would be the basic form of market competition, firms' strategies would change as winners and losers emerge and the differences of firms' strengths become obvious. Some firms would want to become more concentrated in the transmission sector and others would want to focus on the generation and distribution sectors. Buyers and sellers of transmission lines would be created and much divestiture would take place. At the same time, divestiture of generation plants and distribution sectors would also occur. Since all these changes are market driven, there would be no need to worry about windfalls and losses. Also there would be no need to worry about how to compensate present owners, since these exchanges are just normal market transactions.

The final structure of this industry would be driven by efficiency. For example, if owning both genecos and discos without owning transcos does not improve efficiency then the separation of the two parts by divestiture is also inevitable.

No constraints exist for the addition of new power plants. New power plants would have a complex pattern of geographical distribution. Over time, the geographical concentration of power plant ownership resulting from the franchising practice would disappear.

Structure reform can start from a special area where the density of transmission lines is high and the potential of market competition is strong. At the beginning, only several IOUs need to be involved. If the restructuring is successful locally it can be extended nationally.

Advantages and Disadvantages

The new proposal provides a solution to the transmission bottleneck. Once this problem is solved, market forces can work to solve other issues. In general, the system must be able to respond quickly to changing electric demand. Since a transco is an independent managerial entity, no time-consuming contract arrangements will be needed to respond to demand changes. Since fewer transcos will be needed, many genecos and discos will be linked with one transco to form a system that is larger than any of the existing utility systems. Economies of coordination will be realized. The new system would possess all the advantages of a power pool but with less transaction cost.

Competition should not happen within one transmission system since the flow of electricity within a transmission grid is determined by its physical nature. Although gencos and transcos are different entities, reliability concern and market competition force these two sectors to take reliability into account. Due to these reasons, reliability will not be weakened.

Capacity addition will also be driven by market competition and the lead-time of plant construction will be reduced due to simplified regulatory procedures. The risk of individual investment can be high since firms are solely responsible for their investments.

Technological advancement will be facilitated by that fact that genecos and transcos can be very large and able to support R&D. With technological and economic development, the market structure can adjust continuously due to the reduction in regulation.

For the new system, government needs only to provide subsidy or tax relief (driven by equity concerns due to political factors) through discos. The generation and transmission sectors are not affected thereby reducing inefficiency due to equity concerns.

With this new system, the regulatory burden will be reduced however the complexity of regulation will be increased since the organizational structure will be much more diversified than it is now. Given that gencos and transcos will operate at national or at least regional scale, realignment of jurisdiction between FERC and state utility commissions may be needed. Given that discos can be affiliated with firms in other industries, the rate of return regulation may be more difficult and less effective.

Li (1995) provides a detailed comparison of the new proposed structure with the following existing proposals: total deregulation approach, full regulation approach, Weiss's proposal, Cohen's model, Berry's model, direct competition approach, O'Connor's model, Joskow and Schmalensee scenarios, scenarios of The Office of Technology Assessment and the spot pricing approach.

4.7.6.5 Conclusion

The essential feature of the new proposal is to recognize the critical role of the transmission sector in determining the market structure of the entire industry, identify the technological feasibility of market competition in this sector, consider both the costs and benefits of making this sector competitive, and provide schemes to make this sector competitive

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