PN-ABM-048
ISN 78941

ENERGY PRICING REFORM WORKSHOP

MAY 7 - 16, 1991

RENEL TRAINING CENTER
BUCHAREST, ROMANIA

Presented By:
Resource Management Associates of Madison,Inc.

In Cooperation with:

Tellus Institute
and
Energy Price Reform Working Group
Ministry of Resources and Industry
Government of Romania

U.S. EMERGENCY ENERGY PROGRAM
For Eastern and Central Europe
U.S. Agency for International Development
(USAID Project #: 180-0015)

Resource Management Associates of Madison, Inc.
Madison, Wisconsin, U.S.A.

TABLE OF CONTENTS

PREFACE

EXECUTIVE SUMMARY AND RECOMMENDATIONS

1. INTRODUCTION, WORKSHOP OUTLINE AND PARTICIPANT LIST

2. PRESENTATION OUTLINES (SELECTED)
   A. Introduction to Energy Pricing Reform
   B. An Overview of Models and Modeling
   C. Least-Cost Energy Planning
   D. Tariff Design Practices in the United States
   E. Energy Related Environmental Impacts and Their Economic Implications

3. ARTICLES AND REFERENCES
   1. Resource Management Associates. 1991. "Draft Briefing Paper on Energy Pricing Reform in Romania". April 23, 1991.

   2. Hanson, M., S. Kidwell, D. Ray, and R. Stevenson. 1991. "Electric Utility Least-Cost Planning: Making It Work Within a Multiattribute Decision-Making Framework". *Journal of the American Planning Association*, Vol. 57, No. 1, Winter 1991.

   3. Bernow, S., B. Biewald, and D. Marron. 1991. "Full-Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation". *The Electricity Journal*. March 1991.

   4. Ross, M. 1989. "Energy and Transportation in the United States", *Annual Review of Energy,* Vol. 14, 1989.

   5. Oak Ridge Associated Universities. 1980. "Energy Use and Economic Variables". Chapter 3, Industrial Energy Use Data Book. 1980.

   6. Oak Ridge Associated Universities. 1980. "Investment Criteria and Public Policies Toward Industrial Energy Conservation". Chapter 5, Industrial Energy Use Data Book. 1980.

   7. Greene, D.L.. 1989. "CAFE or Price?; An Analysis of the Effects of Federal Fuel Economy Regulations and Gasoline Price on New Car MPG, 1978-89. *The Energy Journal*, Vol. 11, No.3, 1989.

8. United Nations. 1990. "Evolution and Structure of Power Consumptions in the Main Industrial Sectors". Seminar on the Rational Use of Electricity, Romania, 6-8 November, 1990.

9. Drollas, L.P.. 1984. "The Demand for Gasoline". *Energy Economics*, January 1984.

10. Wheaton, W.C.. 1984. "The Long-run Structure of Transportation and Gasoline Demand. *The Bell Journal of Economics*, 1984.

11. Bernow, S. and D. Marron. 1990. "Valuation of Environmental Externalities for Energy Planning and Operations". Tellus Institute, May 18, 1990.

12. Kayser, H. 1991. "On Elasticities in the RMA Transportation Model". Resource Management Associates, April 1991.

4. USER'S GUIDES FOR MODELS
   A. User's Guide to the Industrial Sector Energy Demand Model
   B. User's Guide to the Transportation Sector Energy Demand and Emissions Model
   C. LEAP Model Overview

5. SCENARIO TABLES AND FIGURES

6. OTHER DATA

PREFACE

This Energy Pricing Reform Workshop Notebook is a working document published informally by Resource Management Associates of Madison, Inc. (RMA). To present the results of the project with the least possible delay, this notebook has not been prepared in accordance with the procedures appropriate to our formally printed documents. This notebook has received only light review, in the interest of timeliness.

This work is being carried out within the framework of the U.S. Emergency Energy program for Eastern and Central Europe under an RMA contract with the U.S. Agency for International Development. RMA, as Prime Contractor to USAID, in currently implementing the **Energy Pricing Reform Project** and the **Industrial Energy Efficiency Project** in Romania. The purpose of the Energy Pricing Reform Project is to provide to the Government of Romania an analytical basis for understanding energy flows in the Romanian economy, underlying costs in the provision and use of energy, major environmental consequences of alternative energy strategies, and other information to support the transition to a market-based pricing system.

This notebook provides a copy of materials provided at the Energy Pricing Reform Workshop, materials provided to workshop participants following the workshop, and the executive summary and recommendations from the workshop. The workshop was held in Bucharest in May 1991 in which an RMA team of experts worked with a counterpart group of Romanian experts in identifying what market-based energy prices would be in Roman'^NA mission trip report outlining the major energy pricing issues (April, 1991), a workshop trip report (Buly 1991), and a final Project Report which is anticipated to be completed in September 1991

Executive Summary of Workshop Energy Pricing Scenarios

Three Romanian energy scenarios were developed jointly by the Romanian participants and the RMA team in the Workshop conducted at the RENEL Training Center in Bucharest from Tuesday, May 7 through Thursday, May 16, 1991.

A loose consensus process was used in developing scenarios for the evolution of energy prices and the Romanian economy. The participants, in working groups and in plenary session, developed input values of energy prices and other forecast variables used in scenarios. However, RMA and Tellus Institute provided the methods and computer models and took responsibility for developing initial default coefficients used in the models. While many of these coefficients were discussed, reviewed, and altered during the workshop, time constraints did not allow for a complete review.

As part of the process of transferring analytical methods to Romania and furthering the development of Romanian capability in energy pricing, planning, and management, it is anticipated that participants in the workshop will continue to work with the methods presented. This work includes the development of additional scenarios, modification of the models, and linkage to other ongoing research efforts. The purpose of these efforts is to foster the development of professionals, data bases, models, and other tools to support decision-makers as they make critical energy pricing, investment, and policy decisions.

Treatment of Scenarios

These scenarios are projections into the future. Projections should be used as learning tools, not believed to be the exact truth. The scenarios presented in the following discussions should be assessed under this principle. The models are tools that allow the user to look at possible changes in future energy demand and supply mixes, due to changes in fuel prices, economic growth, and various management discussions.

These scenarios are based on preliminary data developed in the workshop. The preliminary data, model structures, and coefficients were developed in the U.S. by RMA and the Tellus Institute. Since the RMA team was not able to base all the coefficients on historical data from Romania, they may not reflect the responses of the Romanian energy economy in the future; and of course the input data on future energy prices and economic growth may turn out to be different than what actually evolves.

For these reasons we suggest that the appropriate way to treat these scenarios is as follows:

(1) start with developing and using reasonable scenario parameters/coefficients and assumptions for input into the models;

(2) run the scenarios with the models;
(3) analyze how the results were reached from (a) model structure and coefficients, and (b) input data and assumptions;
(4) develop policy scenarios based on "managing" the elements that are causing the results - (a) reinforcing the elements that are causing favorable results, and (b) changing the elements that are causing unfavorable results; and
(5) review the results and their implications for the planning and management of the overall energy system and the economy.

We have organized our comments along the lines suggested above. **We emphasize the need for further, ongoing analysis of key areas and the policy implications of the scenarios.**

1. Scenario Results

Two major results emerge from the scenarios developed in the workshop:

(a) The future demand for electric and other energy is being reduced by the current decline of industrial output and by the transition of industry composition from highly energy intensive to less energy intensive sectors. Energy use could be further substantially reduced by energy efficiency gains associated with major price increases and the adoption of a market economy and its associated flexibility. This combination of factors would substantially reduce Romania's energy imbalances. It would enable Romania to upgrade its energy supply system in a more orderly and less costly manner than has hitherto seemed possible. This result will be reinforced if the government allows and encourages suppliers of energy to respond positively to energy price increases. This supply response - which supplements the demand response which our analysis has concentrated on - could affect the supply mix of electricity, coal, oil and gas.

(b) Some large energy-intensive industries in Romania must face substantial declines unless they can dramatically improve their energy efficiency. Certain energy intensive industries may not be competitive, despite efficiency gains, under international market conditions. Government subsidies would prevent these industries from facing difficult choices; but the cost of these subsidies will increase because they are using energy which, at the margin, consists of imported oil, gas and electricity which have to paid for in hard currency. Furthermore, these subsidies represent an opportunity cost in the form of lost investment funds, which could be used to build up industrial and other sectors which are or can be competitive.

2. Analysis of Scenario Results and Structure of the Models

(a) Model Structure and Coefficients. There are two related features of the RMA

models we have used to develop this analysis. In both the Industrial Sector Energy Demand Model and the Transportation Sector Energy Demand Model, the use of energy is sensitive to the price charged for it. Part of the responsiveness of the industrial sector results from a decline in industrial production in petrochemicals and metallurgy when energy prices rise. The other part of the responsiveness in increased energy efficiency in all industrial sectors is due to price increases. The models incorporate responsiveness through price elasticities which specify the percentage reduction in use of energy for a given increase in the price of energy. We have used moderate but significant elasticities, based on the experience of the United States and other countries which have experienced significant increases in energy prices over the past 20 years.

However, to the extent that the elasticities are greater (or smaller) than those we have used, the responses of industry production and energy use would be greater than (or less than) the responses we have assumed. We would also note that while energy prices are a central element in encouraging the movement of the Romanian economy to a more energy efficient and economically competitive situation, they are not the only element. Constitutional reform, the development of capital markets, the adoption of modern energy management techniques, the development of domestic vendors of efficiency equipment, upgrading of engineering training (particularly in the management area), and other measures are all required for a functional and flexible economy. Once an infrastructure is developed within the country, reduction in energy use through improved energy management and installation of efficient equipment will become significant. The greater the extent of progress in these areas, the more elastic the price responses will be.

(b) Input Data. The scenarios are "driven" by inputs of future energy prices, assumptions of underlying changes in economic output, and indirectly by assumptions of population change. The workshop basically developed three scenarios, labelled "A", "B" and "C". All scenarios assume some further increase of energy prices towards imported energy prices. These prices are shown in Table 1A-1C for industrial energy sources and Table 2 for transportation energy sources.

Two time series are shown by energy type for each of the scenarios. The first series is real (after adjustment for general inflation) prices shown in 1989 Lei. The second series is for relative prices, in real terms, with 1989 prices set equal to 1.0. In light of the substantial inflation now occurring in Romania, the large increases in prices in real terms shown in Tables 1 and 2 indicate enormous increases in energy prices in nominal (without adjustment for inflation) terms. An extremely complex and uncertain task in the workshop was developing assumptions for both the general inflation rate and the exchange rate. The exchange rate had to be explicitly considered in order to relate to border prices in dollars. Exchange rates of 60 and 100 Lei per U.S. dollar were used. An overall inflation rate was also developed in order to evaluate relative price changes. The general price index developed in the workshop had a December 1992 value of 6.0, from a base of 1.0 in 1989.

TABLE 1A: FUEL PRICE CHANGES 1989 TO 2000 FOR SCENARIO A - Industrial Energy Demand Model

	PRICE CHANGES BY FUEL TYPE									
	ELECTRIC		NATURAL GAS		FUEL OIL		COAL		DISTRICT HEAT	
YEAR	REAL PRICES Lei/kwh (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/m3 (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/Ton (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/Ton (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/GJ (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)
1989	0.51	1.00	1000	1.00	1875	1.00	179	1.00	-	1.00
1990	1.08	2.12	2000	2.00	2860	1.53	304	1.70	-	2.12
1991	1.25	2.45	2000	2.00	2800	1.49	304	1.70	-	2.45
1992	1.30	2.55	2000	2.00	2550	1.36	300	1.68	-	2.55
1994	1.30	2.55	2000	2.00	2550	1.36	300	1.68	-	2.55
2000	1.30	2.55	2000	2.00	2550	1.36	300	1.68	-	2.55

TABLE 1B: FUEL PRICE CHANGES 1989 TO 2000 FOR SCENARIO B - Industrial Energy Demand Model

	PRICE CHANGES BY FUEL TYPE									
	ELECTRIC		NATURAL GAS		FUEL OIL		COAL		DISTRICT HEAT	
YEAR	REAL PRICES Lei/kwh (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/m3 (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/Ton (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/Ton (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/GJ (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)
1989	0.51	1.00	1000	1.00	1875	1.00	179	1.00	-	1.00
1990	1.08	2.12	2000	2.00	2860	1.53	304	1.70	-	2.12
1991	1.40	2.75	2200	2.20	2987	1.59	350	1.96	-	2.75
1992	1.40	2.75	2180	2.18	2900	1.55	380	2.12	-	2.75
1994	1.40	2.75	2180	2.18	2900	1.55	380	2.12	-	2.75
2000	1.40	2.75	2180	2.18	2900	1.55	380	2.12	-	2.75

TABLE 1C: FUEL PRICE CHANGES 1989 TO 2000 FOR SCENARIO C - Industrial Energy Demand Model

	PRICE CHANGES BY FUEL TYPE									
	ELECTRIC		NATURAL GAS		FUEL OIL		COAL		DISTRICT HEAT	
YEAR	REAL PRICES Lei/kwh (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/m3 (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/Ton (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/Ton (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)	REAL PRICES Lei/GJ (1989 Lei)	Relative PRICES in Real Lei (1989= 1.0)
1989	0.51	1.00	1000	1.00	1875	1.00	179	1.00	-	1.00
1990	1.08	2.12	2000	2.00	2860	1.53	304	1.70	-	2.12
1991	1.17	2.29	1333	1.33	2800	1.49	305	1.70	-	2.29
1992	1.11	2.18	1178	1.18	2666	1.42	305	1.70	-	2.18
1994	1.11	2.18	1178	1.18	2666	1.42	305	1.70	-	2.18
2000	1.11	2.18	1178	1.18	2666	1.42	305	1.70	-	2.18

TABLE 2: FUEL PRICES FOR SCENARIOS A, B AND C
Transportation Energy Demand Model

RELATIVE FUEL PRICES IN REAL LEI
(Normalized to 1989 Lei)

	Year	Diesel	Gasoline	Electricity
Scenario A	1989	1	1	1
	1990	1.53	1.53	2.12
	1991	2.49	2.49	2.45
	1992	2.36	2.36	2.55
	2000	2.36	2.36	2.55
Scenario B	1989	1	1	1
	1990	1.53	1.53	2.12
	1991	2.59	2.59	2.75
	1992	2.55	2.55	2.75
	2000	2.55	2.55	2.75
Scenario C	1989	1	1	1
	1990	1.53	1.53	2.12
	1991	1.49	1.49	2.29
	1992	1.42	1.42	2.18
	2000	1.42	1.42	2.18

The main differences between the three scenarios are the price assumptions. In Scenario A, energy prices continue the dramatic price increases of 1990 with further large increases by the end of 1991. In the case of transportation energy sources in Table 2, a dramatic jump occurs by the end of 1991 compared to 1990. A major assumption in Scenarios A and B is that Romania adopts a motor fuel taxation policy similar to countries of Western Europe. Relatively minor real price changes for all energy sources occur by the end of 1991 to 1992, followed by stable real prices from 1992 to the year 2000. While real energy prices may be stable from 1992 to the year 2000, nominal energy prices could be rapidly increasing if the overall inflation rate is substantial during this period. Inflation rates in Romania have increased sharply during the last two years and one of the challenges to the economy will be to bring inflation under control.

Scenario B has somewhat higher price increases than Scenario A after 1990. It uses the largest price increases that could be anticipated by the workshop participants, on a consensus basis. In comparison, Scenario C has the same price increases in 1990 as Scenarios A and B, but the prices are lower from 1991 to 2000 relative to the other scenarios. Scenario C assumes that natural gas prices, after the large price jump of 1990, will return to almost their 1989 level in real terms. Finally, transportation fuels are priced in a fashion similar to U.S. pricing, with relatively modest taxes. Thus, Scenario C transportation fuel prices are considerably lower than in Scenarios A and B.

The economic and energy responses to the three scenarios are summarized in tabular and graphic form in Section 7. The industrial model results are shown in Section 7, and include fuel use by subsector, and by fuel type; sectoral growth rates; energy intensity; percentage price increase; sectoral percentage shares of industrial output and energy use; and sectoral gross industrial product. In addition, relative price changes and energy demand and output price elasticities are given. In evaluating these results, it is important to note the changes in the output price responses as well as the changes in energy prices. Importantly, in Scenarios B and C, the output elasticities are altered from the model default values (see output price responses for Scenario A showing uniform output price responses across all industrial sectors) to values where most industries do not have an output response except the very heavy energy users (metallurgy and petrochemicals) where the output elasticities increase considerably.

The net effect of the output elasticity and energy price assumptions is that Scenario B, with the highest price increases, has the lowest energy consumption in 1994 and 2000 while Scenario C, with the lowest energy price increases, has the largest energy consumption. These results reflect the massive restructuring of the Romanian industrial sector and economy in general. Due to economic changes since 1988, assumed underlying sectoral growth rates, and the influence of energy prices; the metallurgical and chemical industries face considerable decline. The decline results from the assumption that significantly higher energy prices will render these energy intensive industries unable to profitably compete in some international markets. Other sectors,

particularly machinery and food products, show rapid recovery after initial decline.

Transportation results are provided in Appendix D and parallel the results of the industrial analysis with the highest energy use levels occurring in Scenario C while the lowest occur in Scenario B. Section 7 shows the relative fuel prices, GDP (Gross Domestic Product) and Industrial GDP, elasticities, and final energy consumption values for both freight and passenger transportation which were used for each scenario. The GDP, Industrial GDP, and the elasticities are the same for all scenarios, whereas the fuel prices change similarly to those in the industrial model. In reviewing the transportation model runs after the workshops, we found that National and industrial Gross Domestic Product values need to be adjusted. The final workshop notebooks will show the revised values and their results in the transportation sector.

The aggregate results of industrial and transportation energy demand, demand from other uses, and supply analysis are summarized in Table 3. Perhaps the most significant result is that industry energy use is lower in the year 2000 in all scenarios than in 1989 (which was considerably lower than 1988 values). Transportation energy use in the year 2000 was only slightly higher than the year 1989, showing the relative inelasticity of transport fuel use to price changes. In addition, the energy required from each energy source is lower except in the case of oil which, by the year 2000, is modestly higher in all scenarios. As described above, a decline in energy demand during the 1990's would remove considerable pressure from Romania in terms of investment requirements, operating expenses, and environmental consequences in supplying the nation's energy needs.

3. Development of Policy Scenarios Based on "Managing" Romania's Energy Future

(a) Reinforcing the Positive Factors. Energy conservation services provided to industry and to consumers would reinforce the economy's response to energy price increases and would enable consumers to reduce the economic distress caused by such changes. **More broadly, market reforms including conversion to private ownership, currency convertibility, firm management autonomy, market based prices including regulated utility prices based on market costs, and the support of private energy services firms would provide the flexibility for industry to respond to market prices. Private energy service firms should be encouraged and include firms in finance, engineering, equipment, sales, and marketing.**

TABLE 3: SUMMARY ENERGY DEMAND AND SUPPLY FOR 1989, 1994 AND 2000
ALL VALUES IN 10 E+18 JOULES

		SCENARIO A		SCENARIO B		SCENARIO C	
	1989	1994	2000	1994	2000	1994	2000
DEMAND (END-USE)							
INDUSTRY	1.9	1	1.3	0.9	1.1	1.2	1.5
TRANSPORT	0.45	0.34	0.47	0.33	0.46	0.4	0.55
TOTAL	2.35	1.42	1.76	1.3	1.6	1.6	2
ELECTRICITY DEMAND	0.26	0.17	0.21	0.16	0.2	0.19	0.22
DISTRICT HEAT DEMAND	0.53	0.34	0.41	0.34	0.41	0.37	0.4
SUPPLY (PRIMARY)							
NATURAL GAS	1.6	0.87	1.1	0.83	1	1.1	1.3
CRUDE OIL	1	0.79	1.1	0.77	1.1	0.92	1.2
LIGNITE	0.78	0.49	0.59	0.39	0.48	0.47	0.57
EXPORT OF PRODUCTS	-0.13	-0.12	-0.23	-0.13	-0.23	-0.16	-0.2
TOTAL (CORRECTED FOR EXPORTS)	3.3	2.1	2.6	1.9	2.4	2.4	2.9
ALL IMPORTS	1.5	0.54	0.96	0.52	0.85	0.67	1.1

(b) Mitigating the Negative Factors. The principal negative factor evident in the scenarios is the economic distress of industries and consumers. Subsidies to **distressed industries** do not provide long-term relief. Financial assistance provided by private sources, the government, and other agencies such as the World Bank should be targeted at improving the overall efficiencies, including energy efficiency, of many but not all existing industries, including some energy intensive industries, and building new competitive industries.

Domestic consumers (residential population) account directly for only about 10 percent of total Romanian energy consumption. Allowing only gradual increases in consumer energy prices would not substantially decrease economic efficiency. It is important to steadily reduce the implicit subsidy over time, lest inefficiencies build up. Motor fuel prices have been priced at world market levels (without Western European tax levels) and should remain at least at current levels in real Lei. Two of the scenarios considered even greater price increases to levels typical of much of Western Europe.

4. Recommendations

The main purpose of the workshop was to develop and discuss a number energy pricing structures and not to recommend specific energy prices and tariff levels for Romania. Therefore, pricing structures were explored and three pricing scenarios were identified and used for evaluating the potential response of the economy to the large price increases that would result from the adoption of market-based energy prices.

In developing the price scenarios, however, three fundamental approaches were considered: 1) using international and/or border prices, 2) using long-run marginal cost, and 3) allowing purely market determined prices. The result of using the first approach in helping to set the scenario prices was that energy prices continued to increase rapidly through 1992. From 1992 to 2000, energy prices would continue to increase at the overall rate of inflation so as to maintain their relative position.

The energy pricing workshop emphasized a fundamental concept of economics - prices which do not reflect economic costs introduce distortions which result in large net losses to society. Thus, a subsidy of a million lei, through charging a subsidized energy price to an energy-intensive industry, is not simply a transfer of one million lei from one group (energy producers or taxpayers) to another (the industry, its suppliers and employees). Because of the false price message, the industry may be wrongly encouraged to grow, and is discouraged from conserving energy. Likewise, because of reduced profits, the energy producers - including potential new producers - are discouraged from increasing the supply of energy.

The next few years will present the Romanian economy and the Romanian energy sector with some debilitating changes. By alleviating some of Romania's energy crisis through

the adoption of market structures and incentives, i.e., least-cost planning; market oriented management; and integration of supply and demand improvements, the transition will be less painful.

The following recommendations address the above issues.

4a. Energy Pricing Reform and Energy Management Recommendations

There are a number of planning and management actions which would support the transition of the Romanian economy to a market economy and improve the efficiency of the energy sector. These are:

1. **Energy Prices.** Based on the project effort to date, we recommend that work should continue to improve estimates of cost based prices using long-run marginal cost in the area of electric power and natural gas (regulated utilities in market-economies).
RENEL has a considerable accounting system which, if updated to include a new calculations of cost of capital and other changes, could be used to estimate prices. Simultaneously, RENEL should be aided in coming up to date in the areas of tariff design. This is both a matter of tariff structure and the metering systems required for a modern tariff structure. Thus, as cost estimates increase with more accurate data, rates can be raised accordingly.

   To spur domestic production, as well as efficient use of the resources, the recent policy of using border prices for domestic crude oil and gas production appears appropriate. As noted in the workshop discussion, however, there is a need to reconsider existing taxation policy and perhaps shift it to a tax on profits rather than on revenue. The resulting prices for crude oil and natural gas should then be accurately reflected at refineries and at power plants (for heavy fuel oil).

   For fuels where market determined prices could be used, for example retail sales of gasoline, the recent decision to allow market determined prices where three or more suppliers are present is a move in the right direction. Monitoring will be needed to see if three firms are really sufficient in a market to support fair prices. Thus, it would seem appropriate to estimate cost based prices for these markets in order to determine whether any "gouging" is occurring. There is opportunity for market based prices both in the sales of some energy products as well as in the area of primary production. Monitoring will be required, however, to evaluate how successful the markets are.

   Finally, we believe there may be opportunity to introduce competition in the power sector. This could be achieved by the introduction of private power through the sale of existing plants to private owners and/or the introduction of

new plants on a competitive basis. This opportunity will require regulatory reform as well as resolution of the constitutional reforms underway.

For a broader discussion of pricing and background issues, see the "Briefing Paper: Energy Price Reform in Romania" in the April 23, 1991, RMA Energy Pricing Reconnaissance Trip Report (RMA/ROM-RR-01).

2. A strategic electric **system refurbishment/expansion plan.** The scenarios indicate that Romania will need less power in the future than was anticipated in past forecasts by Romanian authorities. While this relieves pressure for new plant capacity, it places even greater focus on the need for a strategic plan for retrofitting the power system to improve overall availability, energy efficiency, overall cost reduction, and emissions reduction. A systematic long-term (10 to 20 years) plan for overhauling existing capacity is recommended. Such a plan should be carried out in close collaboration with RENEL and such a plan should address the sequence of plants to be retrofitted, and transportation and distribution improvements to be made. These activities will reduce losses within the supply system as well as make more capacity available.

3. **Demand-side management plan.** Considerable industrial energy efficiency improvements can be made at current prices, although even greater improvements are both possible and cost effective at the prices anticipated in the scenarios. The current RMA audit program and industrial profile report should be reviewed as soon as it is available, and comparisons made between the relative advantages of investment in industrial demand-side investments versus investments in the electric, petroleum and coal systems. Both demand-side and supply-side investments are needed, the issue is how much of each.

   Demand-side management activities should be implemented both within the national utility system and throughout industries at an individual plant level. Promotion and implementation of demand-side energy conservation measures should be integrated with utility generation plans, as conserving energy has often proved to be more cost effective than building new energy supply. RENEL's charter should be redefined by the government and RENEL to include provision of demand-side management services, in addition to traditional supply side services. Technical Assistance in this area will be required and could be provided by international donor or lending institutions.

   In conjunction with the demand-side activities proposed above, an industrial efficiency investment program is recommended to be established through the Romanian government (the Energy Division of the Ministry of Industry could be the lead agency) or an appropriate non-governmental institution. This program should be established as a market-oriented energy loan program. Such a program would provide capital for energy efficiency investments. Loans could cover

design, equipment, and installation costs and be administered by private lending agencies. Technical assistance by international donors would be an option, particularly in the first two to four years of the program, given a program duration of seven to ten years. (One example that could be followed in some respects is the USAID funded Technology Transfer for Energy Management Program (TTEM), an industrial energy conservation demonstration loan program.) This program could be funded by international lenders. In order that the program has a significant impact, it should have substantial funding, about $15 -60 million in loans, and long term (5-10 years) duration.

Any demand-side management lending program should explicitly consider the capability of various industrial sectors to survive the transition to a market economy. It is anticipated that the need to secure loans will in part control lending practices.

4. **Restructuring of energy regulatory institutions** of Romania could increase the supply-side responsiveness to energy price increases. A regulatory framework should be created which encourages independent power producers to enter the market - particularly municipal and industrial cogenerators as well as integration of demand side measures into supply plans. Such a regulatory restructuring may involve the establishment of an independent regulatory commission typical of the U.S. and some other market economies. Such commissions, if carefully designed and administered, provide for a greater level of public confidence in the fairness of energy price levels and removes some of the onus of energy price increases from the government.

5. **Tax reform of the energy sector** should be evaluated for its impact on energy production levels. The current taxation system appears to drain away much of the profit from the oil and gas business. We cannot believe that sufficient incentive remains for the most active and imaginative exploration, development and recovery of oil and gas. A tax system which focuses on taxation of profits and which provides incentives for investment should be reviewed. This is particularly important for the adoption of equipment for secondary and tertiary recovery that can markedly increase the production rate and yield from the Romanian oil and gas fields. Tax and profit sharing arrangements which encourage joint production and other creative arrangements should be systematically explored.

6. **Education and Training** support is critical to encouraging improvement of energy management in both the short and long run. A support program for existing training institutions, such as the RENEL training center should be considered. Longer term educational support in the form of visiting professorships in energy management and engineering and the establishment of curriculum in these areas at the Polytechnical University and other universities should also be considered. In addition, in-plant training in energy management and the improvement of in-

country technical expertise in this area should be considered. Training and local expertise will be greatly enhanced by the provision of microcomputers and software at existing training institutions.

7. **Refinery model development for scheduling and planning.** Romania is one of the only countries in the world operating a major refining industry without computer models. The cost of not having computer model support is enormous. Without it, it is impossible for Romanian refineries to operate at a profit in an open world market. While other refinery investments are also needed, a refinery model development initiative is a necessary investment at this time.

Near term:

Develop distribution models for the oil and gas sector to optimize distribution costs from fields to refineries and power plants, and from refineries to demand centers. This project would take the form of a workshop on distribution modeling, consulting on data acquisition for volumes and transportation costs, computer model development and training in use. Labor required would be about 6 person-months. A computer workstation similar to the IBM AS6000 (IBM, DEC, SUN and HP all make suitable equipment), would be required. A license to some software such as the Chesapeake Decision Sciences MIMI/LPE model for production planning would be required (a single site license would be sufficient for this project). MIMI/LP is a linear program modeling package developed for refinery applications.

Such models would be invaluable for optimization of the existing system and performing economic analyses on future modifications. For example, if some refineries are shut down and their function combined with other refineries, the changes in the distribution system need to be optimized. Data for this type of model is adequate at present.

Long term:

Develop refinery planning models for use at each refinery for monthly operations planning and economic analysis. A production planning and scheduling model such as Chesapeake's MIMI/E would be used. This project would be comprised of a workshop on refinery modeling and planning, model development for each refinery and training on their operation. This project would have to be delayed until measurement and control capability in refineries is adequate to provide current status and plan implementation capabilities. A project could start as soon as a refinery had this capability. Labor required would be about 4 person-months plus 2 person-months for each refinery model. A workstation similar to an IBM AS6000 would be required in each refinery plus at least one in the central office in Bucharest. A site license for would be required at each refinery. A one time

purchase of a set of process planning computer models will also be required.

Develop refinery scheduling applications within each refinery for hourly process and tankage scheduling. This replaces hand scheduling and allows more efficient implementation of the optimum operating plan. The project labor required would be about 2 person-months for a workshop on scheduling and about 2 person-months per refinery for implementation and training. A license for software would be required at each site as a small addition to existing licenses.

U.S. Emergency Energy Program
Workshop on Energy Pricing Reform in Romania

May 1, 1991

INTRODUCTION

Romania faces many challenges as it manages the present and looks to the future. One of the central challenges is the transition from a centrally planned, command and control economy to a market based economy. At the heart of this transition is the issue of prices, for in a market economy prices and people's preferences are the central pieces' of information influencing behavior of both households and firms.

The focus of this workshop is energy prices. To understand them and how the economy may respond to them requires an understanding of a number of items including: 1) underlying cost of energy provision, 2) the structure of the market for the various energy products, 3) potential regulatory mechanisms for establishing prices , especially where natural monopoly exists, 4)the responses of the economy to price changes, and 5) the relationship of energy prices to other prices in the economy.

The purpose of this workshop is <u>not</u> to determine what the price of various energy products should be. The decision on how energy prices should be determined, whether by markets or regulation, is a difficult and highly sensitive one that must be decided at the highest levels of the Government of Romania. The purposes of the workshop, however, are to explore the items listed above, potential price levels and structures, their implications for the Romanian economy, and the experience of other market economies in energy pricing.

In fulfilling these purposes, computer models will be used to evaluate various pricing scenarios. By the end of the workshop, the Romanian participants will have developed some initial energy pricing scenarios. While these models will facilitate our understanding of energy pricing reform, they can not by themselves determine what prices should be. Both the models and the computers on which they are run are provided to the Government of Romania so that the work which will only begin at this workshop can continue into the future. Indeed, energy management and the computer techniques to support that management are ongoing activities.

Resource Management Associates and the Tellus Institute look forward to working with all of you in what we hope is an important and rewarding workshop.

Workshop Outline and Schedule

May 7

am	- Introduction of workshop participants and their responsibilities in energy pricing - Workshop overview and introduction to energy pricing reform - Review of the April price adjustments by EPRWG members
pm	- Models and modeling overview
evening	- Reception

May 8

am	- Least-cost energy planning and other economic principles (societal costs) - Discussion session on alternative pricing policies
pm	- LEAP working session - Industrial Sector Energy Demand Model working session
evening	- PUBLIC LECTURE: Least-cost Planning - Hanson

May 9

am	- Electricity revenue requirements Generation Transmission Distribution Administrative - EPRWG discussion of electricity scenarios
pm	- Revenue spreadsheet - Industrial working session
evening	- PUBLIC LECTURE: Electricity Pricing Practices in Market Economies - Talbot

May 10

am	- Energy price responses in a market economy - EPRWG discussion of fossil price scenarios, including taxation treatment
pm	- Transportation Sector Energy Demand Model Introduction - LEAP working session

May 13

am	- Oil, gas, and coal pricing - EPRWG discussion of pricing/demand scenarios
pm	- Transportation working session - LEAP working session - Refinery cost and scheduling modeling
evening	- PUBLIC PANEL DISCUSSION: Energy Price Responses in a Market Economy - Musatescu, Hanson, Talbot

May 14

am	- Technical staff report on scenario analysis - EPRWG discussion of scenarios and preliminary results
pm	- Refinery analysis - Scenario runs
evening	- PUBLIC LECTURE: Energy Related Environmental Impacts and their Economic Implications - Bartels

May 15

am	- Plenary working session Energy pricing scenarios Sectoral responses to price change Institutional development: regulatory and environmental
pm	- Final scenario runs and report writing

May 16

am/pm	- Plenary presentation of pricing options and consequences by EPRWG and technical staff - Discussions of pricing options - Future work areas in next phase of project - Follow-on opportunities
evening	Closing Ceremony

LIST OF PARTICIPANTS
ROMANIAN WORKSHOP

Albulescu, Gheorghe	Rafinaria Cimpina
Alica, Aglaia	Rafinaria Cimpina
Aretu, Marian	Dept. of Minerals, director general
Armencea, Mihai	Ministry of Industry, Budget Division, price sr. expert
Arusoaie, Virgi	RENEL
Bilegan, Liana	Instit. de cercetari Energetice
Bolma, Ion	RENEL, engineer
Buhus, Pavel	Polytechnical Institute, professor
Burghelea, Anca	Dept. of Chemistry - Centrul de calcul
Busuioc, Alexandru	Dir. generala de producerea en. el. si termice, economist
Calin, Valentin	RENEL
Capaciu, Floricare	PETROMIDIA
Capitanu, Florea	PETROTEL S. A. Poloresti, engineer
Caplat, Ion	RAFO SA Onesto, engineer
Carlan, Miltiade	Centrulde perf-a lucrat RENEL
Coculescu, Serban	RENEL, engineer
Costin, Emil	RENEL, engineer
Croitoru, Geta	Dir. generala de producerea en. el. si termice, economist
Criotoru, Daniela	PETROMIDIA, engineer
Cupaciu, Florica	PETROMIDIA, engineer
Damian, Silvia	Ministry of Industry, Energy Division, economist
Darie, Lorenzina	Director de transp. si distrib. energiei el., engineer
Davidescu, Reveica	Ministry of Industry, Dept. of Petrochemicals, economist
Diaconu, Anca	RENEL
Dobrin, Mircia	RENEL, Training Center, deputy manager
Doleriu, Ion	Rafinaria Pitesti
Dragan, Florea	Ministry of Economics and Finance, engineer
Dragan, Nicolae	Mining Dept., pricing senior expert
Dumitrescu, Daniel	Dept. of Industrial Chemicals - Centrul del Calcul
Dumitrescu, Mioara	Ministry of Economics and Finance-pe. preture
Dumitru, Danila	Filiala Retele Electr. Focsani
Florea, Cornel	Ministry of Industry, Public Relations, deputy manager
Fulger, Titina	ICEMENERG, engineer
Ghelmez, Melania	Directia gen. de producere a en el si termice
Ghenici, Mircea	Energoreparatic
Gherghina, Alex	Instit. de Stadii si proiect hidro enertetice, engineer
Gliga, Radu	ICEMENERG
Gugu, Florin	ISPE, engineer
Huian, Gheorghe	Instit. de Mecanica Fina
Iancu, Gabriel	PETROTEL S. A. Ploiesti
Ichim, Lucretia	PETROMIDIA
Indre, Gheorghe	Directia gen. de transport si distrib. energy el., engineer
Indre, Mihaela	Intrep. de distrib. energiei Buc.

Ionescu, Traian	Instit. de cercet. energetice
Iordache, Marie-Jeanne	RENEL, engineer
Isaroiu, Viorel	ICEMENERG
Lazar, Ioan	Ministry of Industry, Budget Division, deputy manager
Lazarescu, Olga	Metalurgy Dept., pricing expert
Lisita, Adrian	RENEL, analyst
Manea, Dumitru	RENEL, engineer
Metes, Petru	RENEL, engineer
Moraru, Andrie	Ministry of Industry, Public Relations Division, senior advisor
Musat, Eufemia	Ministry of Industry
Musatescu, Virgil	Ministry of Industry, Energy Division, general manager
Nenita, Maria	Dispeceral Energetic National, engineer
Nichita, Ion	Dir. General a de prod. en. el. si term, engineer
Olteanu, Bujor	Instit. project ind. petrol SA, engineer
Paiu, Daniela	PETROTEL S.A. Ploiesti
Parauta, Mariana	Petrochim. Brazi, economist
Pasculescu, Lia	RENEL, engineer
Popescu, Carmen	Ministry of Industry, Dept. of Industrial Chemicals
Popescu, Catalina	PETROTEL S.A. Plaiesti
Popescu, Miron	RENEL, Training Center, manager
Popescu, Monica	ISPE, engineer
Popescu, Oana	Instit. de Studie si proiect energy
Popovici, Doina	RENEL
Popvici, Raluca	SC "Steaua romana" SA Cimpina
Predescu, Grigore	PETROTEL S.A. Ploiesti
Radoescu, Marinela	Directia gen. de producere a en. el. si termice
Ragalie, Stefan	Ministry of Finance, finance expert
Rosu, Ilie	Dir. Generala de prod. en. el. si term
Rugina, Vasile	ICEMENERG
Rusea, Tudorel	PETROTEL S.A. Ploiesti
Rusei, Nicolae	RAFO SA Onesti
Rusu, Neculai	RAFO ONESTI, engineer
Scripcariu, Daniela	Polytechnical Institute
Siliste, Cornel	Ministry of Industry, Metalurgy Dept., Budget Division, deputy manager
Singeorzan, Daniela	Dir. generala de producerea en. el si termice, economist
Stanciu, Ion	RAFO SA Onesti
Stoica, Mihai	Polytechnical Institute, professor
Suta, Gheorghe	Dir. Generala de producera en. el. si termice, engineer
Tudor, Petre	Directia gen. de. prod. energiei el. si termice, engineer
Tudorel, Constantinescu	Ministry of Industry
Turica, Craita	PETROTEL S. A.
Vaduva, Lucia	Ministry of Industry, Dept. of Chemicals, pricing expert
Valcereanu, Gheorghe	RENEL
Varanta, Mariana	C. Petrochimica Brazi
Vasile, Anisoara	PETROMIDIA
Vintila, Ion	PETROTEL S.A. Ploiesti

Vionea, Dumitru	PETROTEL S.A. Ploiesti
Vionea, Elena	Ministry of Industry
Zingeorzan, Daniela	RENEL, economist

Translators

Agiopol, Mirela	Institutul de studii si proiect energetice, translator
Crainicu, Illeana	Directia Gen. Producere Energie el., translator
Hagiopol, Mirela	ISPE, translator
Ligia, Sendrea	GEOTEC, translator
Tontici, Paula	ISPH, translator

INTRODUCTION TO ENERGY PRICING REFORM

1. WHAT IS A MARKET-BASED PRICE?

    a. Prices of internationally traded energy commodities

    b. Prices of non-traded energy commodities

    c. Prices under natural monopoly

2. DETERMINING MARKET-BASED PRICES

    a. Free market prices and price reporting

    b. Use of accounting costs for regulated utilities

    c. Long-run marginal cost pricing

3. CONSUMER RESPONSE TO MARKET-BASED PRICES

    a. Firms

    b. Households

    c. Service sector

4. MARKET BEHAVIOR AND MACROECONOMIC ISSUES

    a. Supply, demand, and equilibrium

        1. Input markets
        2. Output markets
        3. Natural resources
        4. Waste products

    b. Market failures

        1. General
        2. In energy commodities

    c. Macroeconomic implications of efficient energy markets

    d. The use of the industrial, transportation and leap models to represent market

22

behavior

5. REGULATORY SUPPORT OF MARKET-BASED PRICING

   a. Institutional responses to market failure

   b. Regulatory mechanisms

   c. Market mechanisms

6. PUBLIC POLICY ISSUES

   a. Social and environmental issues

   b. Least-cost planning as an organizing framework

23

AN OVERVIEW OF MODELS AND MODELING
May 7 pm

1. INTRODUCTION TO MODELS

    a. Definition
    b. Types
    c. Purpose
    d. Use of scenarios

2. OVERVIEW OF MODELS USED IN THE WORKSHOP

    a. Industrial model

        1. Structure
        2. Model drivers
        3. Intermediate and final results
        4. Interaction with other sectors/models
        5. Strengths and weaknesses

    b. Transportation model

        1. Structure
        2. Model drivers
        3. Intermediate and final results
        4. Interaction with other sectors/models
        5. Strengths and weaknesses

    c. Leap model

        1. Structure
        2. Model drivers
        3. Intermediate and final results
        4. Interaction with other sectors/models
        5. Strengths and weaknesses

    d. Cost accounting models of power and refining

        1. Structure
        2. Model drivers
        3. Intermediate and final results
        4. Interaction with other sectors/models
        5. Strengths and weaknesses

24

3. SCENARIO DEFINITION

   a. Sets of assumptions

   b. (See summary page)
   c. Consistency issues

      1. Time frame
      2. Identical assumptions
      3. Market clearing

   d. Uncertainty

   e. Portraying policy options with scenarios

4. MODEL USE

   a. Forecasting versus understanding

   b. Modeling as sequential hypothesis testing

   c. Translating model results to policy

25

LEAST-COST ENERGY PLANNING

I. THE CURRENT REVOLUTION IN ENERGY PLANNING IN MARKET ECONOMIES

- A. Problems Facing the Energy Sector in Market Economies
- B. Commonality of Problems in Market and Centrally Planned Economies
- C. Monopoly Power and the Regulatory Requirement
- D. Increasing Competition in Regulated Energy Industries under PURPA
  1. Private Power
  2. Competitive Bidding
- E. Privatization of Public Utilities in Great Britain

II. TRADITIONAL ELECTRIC UTILITY PLANNING

- A. Definitions
- B. Description of Planning Process
  1. Parties to the Planning Process
  2. Role of Utilities
  3. Role of Intervenors
  4. Role of Regulators
  5. Threshold Criteria
- C. Performance and Limitations
  1. Energy Service Costs
  2. Over-construction by Some Utilities
  3. Supply-Side Focus
  4. Environmental Issues

III. LEAST-COST PLANNING

- A. Definition and Genesis of Least-Cost Planning
- B. The Role of Demand-Side Management
- C. Balancing Demand-Side and Supply-Side Measures
- D. Consideration of Other Consequences
  1. Environmental
  2. Social

26

III. LEAST-COST PLANNING (Continued)

E. Least-Cost Planning Process
   1. Parties to the Process
   2. Role of Utilities
   3. Role of Intervenors
   4. Role of Regulators
   5. Decision-Making Criteria
   6. Advance Plan Process
   7. Incorporating Competition

F. Integrated Supply Curves as a Methodology to Support Least-Cost Planning

E. Examples
   1. Wisconsin
   2. Sweden
   3. England

IV. IMPLICATIONS FOR ROMANIA

A. Observations on Applicability
   1. Electrical and Natural Gas Supply Structure
   2. Accounting Procedures
   3. Current Problems

B. Role of Independent, Judicial Regulatory Body

TARIFF DESIGN PRACTICES IN THE UNITED STATES

I. STRUCTURE OF UTILITY REGULATION IN THE UNITED STATES

A. Predominately Private (Investor Owned) Companies

1. Granted Monopoly Franchises

2. Subject to Direct Regulation At Federal and State Levels

B. Quasi-Judicial Regulatory Body

1. Administrative Versus Legislative Structure

C. Rate Base/Rate of Return Price Regulation

1. Revenues Are Set to Collect Total Cost of Providing Service, Including a Fair Return on Investment (ROI)

   Rev. Req. = Expenses + (Rate Base * ROI)

D. Public Adversarial Process

1. Utility Files Formal Documents in Support of Rate Request
   a. Estimated Revenue Requirements
   b. Division of Revenue Requirements Amongst Customer Classes
   c. Proposed Tariffs

2. Parties Debate Technical and Policy Merits of Proposal Before Commission
   a. Parties Have Rights of Discovery that Compel Utilities to Provide Information

E. Publicly Owned Utilities

1. Costing and Pricing Practices Often Mimic Private Utility Regulation

2. Sometimes Legislative Versus Administrative Control

3. Infrequent Changes in Mandate Versus Frequent Rate Case Orders

II. CRITERIA FOR SOUND RATE STRUCTURE

A. Classical Considerations

1. Practical
   Simple, understandable, publicly acceptable, and feasible regarding application

2. Clear
   Freedom from controversies as to proper interpretation

3. Yield Total Revenue Requirements
   Expenses and Return on Investment

4. Revenue Stability

5. Rate Stability
   Minimize of unexpected changes

6. Fair Among Customers

7. Avoids "Undue Discrimination"

8. Discourages Wasteful Use and Promotes All Justifiable Use of Service (Promotes Efficient Use of Resources)

Condensed From: James Bonbright, Principles of Public Utility Rates

B. Other Considerations

1. Economic Development

2. Environmental Impacts

III. RATE MAKING PROCESS

A. Cost Based, Not Value Based Rate making

This debate has involved setting the price of public services at the value to the customer or at the cost of the supplier. It has been largely settled in favor of cost based rate making.

B. Three Step Process of Rate Making

1. Determine Revenue Requirement for Company

2. Class Cost Allocation to Customer Classes (Residential, Commercial, and Industrial)

3. Tariff Design for Each Customer Class

IV. REVENUE REQUIREMENT

A. Purpose

To determine the total revenues required to maintain the utility as a viable entity to ensure the continued provision of public utility service of a desired quality.

B. General Approach

1. Expenses
   Estimated for a designated period assuming normal operating conditions

   Includes fuel, operation and maintenance, depreciation, insurance, taxes, administration and general, etc.

2. Rate Base
   Determined based upon capital dedicated to the public service

3. Return on Investment
   Embedded debt cost plus market based return on equity

V. ALLOCATING CLASS REVENUE RESPONSIBILITY

A. General Approach

Zero sum game. Any costs not supported by one customer group are supported by other groups.

Typically Based Upon Fully Distributed, Embedded Costs
Exceptions
- Marginal Cost
- Legislative Mandate (Governmental Agencies Only)

B. Embedded Allocation: Mechanics

Allocation of total revenue requirement amongst customer groups based upon historic causal relationships.

Begins with system of accounts which in the aggregate equal revenue requirements.

1. Functionalization

   a. Purpose: Groups costs according to function to which they relate.

   b. Primary Functions
      (1) Production
      (2) Transmission
      (3) Distribution
      (4) General

2. Classification

   a. Purpose: Arrangement of functionally grouped costs according to their relationship to measurable cost-defining characteristics of service.

      Functional groups can be spread among more than one classification.

   b. Principal Classifications
      (1) Energy
      (2) Demand
      (3) Customer

3. Allocation

   a. Purpose: Selection of particular factors related to classification which allows assignment to particular customer groups.

C. Example: Coal Fired Base Load Generating Station

1. Functionalization: Production

2. Classification: Energy and Demand

3. Allocation: 50% Relative Class Consumption (kWh)
   50% Class Contribution to System Peak Demand (kW)

D. Points of Debate in Embedded Allocation

1. Classification and Allocation of Generation Costs Among Demand and Energy
   a. Fixed vs Variable
   b. Non-Coincident Peak (NCP)
   c. Coincident Peak (CP)
   d. Average and Excess

2. Classification and Allocation of Distribution Costs Among Demand and Customer
   a. Minimal (or Phantom) System
      Customer charges based upon the minimal system necessary to provide voltage but not power; remaining costs allocated based upon NCP
   b. Minimum Component or Minimum-Intercept Methods

3. Classification and Allocation of Administrative and General Costs

VI. DESIGNING TARIFFS

A. Principal Tasks

1. Determination of Tariff Components
   E.g., Customer, Energy, Demand, Power Factor Charges

2. Determination of Structure of Tariff Components
   E.g., Block Structures, Ratchets

3. Determination of Price for Each Tariff Component

B. Embedded Cost Tariff Design

1. General Approach

   Embedded cost of service study produces unit costs (e.g., customer, demand, and energy charges).

   Structure of tariff (e.g., blocking) and detailed pricing (e.g., pricing of individual blocks) is based upon manipulation of average costs for each component in light characteristics of customer demand.

2. Pros

   a. Cost of components stem directly from allocation of revenue requirements providing total coverage of cost responsibility

   b. Costs are assigned on the basis of the reasons they were incurred

3. Cons

   a. Historic drivers of system development may no longer be related to current uses

   b. May not send correct price signals to consumers

C. Marginal Cost Tariff Design

1. General Approach

A marginal cost study is performed to yield the marginal, (incremental or decremental) costs associated with a marginal (incremental or decremental) change in the number of customers, demand, and energy.

These costs can be related to the individual tariff components; number of customers to customer charge, demand to demand, and energy to energy.

2. Pros

a. Assigns costs in a forward looking manner to send appropriate price signals to consumers

b. Pricing may complement resource development

c. External impacts of electricity use can be incorporated into pricing

3. Cons

a. Not Tied to Utility Accounts
   (1) Ideal prices may not generate desired revenue requirements
   (2) Requires projection of incremental costs

4. Principal Issues

a. Sufficiency of Period Analyzed
   Long-Term Avoided Costs versus Short-term Marginal Costs

b. Determination of Marginal Costs
   To Meet Incremental Consumer Demands
   (1) Customer
   (2) Demand
   (3) Energy

c. Fulfilling Revenue Requirements
   (1) Potential over-collection requires decreasing at least one component below marginal cost
   (2) Potential under-collection requires increasing at least one component above marginal cost

D. Points of Debate in Tariff Design
Common to Embedded and Marginal Approaches

1. Blocks or Their Equivalent in Rate Design

2. Determination of Pricing Periods
Seasonal, Weekly, Daily

3. Whether to recognize External Impacts on Society
   a. Environmental Damage
   b. Economic Development

VII. BASIC INFORMATION REQUIREMENTS

A. Load Research

1. Determination of Usage Characteristics Stratified by Average Usage Level
   a. Contribution to System Coincident Peak
   b. Contribution to Class Coincident Peak
   c. Non-Coincident Peak (Customer Peak)

2. Elasticity of Customer Demands

B. Accounting Information

1. Utility Accounts Suitable for Functionalization and Classification

2. Embedded Cost of Service Study

C. Planning Studies

1. Marginal Cost

2. Long-Term Avoided Costs

3. Stress Factor Analysis

ENERGY RELATED ENVIRONMENTAL IMPACTS AND THEIR ECONOMIC IMPLICATIONS

I. WHAT ARE ENVIRONMENTAL IMPACTS

A. Changes to the natural and social environment resulting from a specific activity by itself or in combination with other activities

B. Progression of environmental impacts

1. Emission loadings
2. Transportation
3. Exposure
4. Dose/Response
5. Impact ("Damage")

C. Common emission loadings and selected damages associated with energy facilities

1. Air Emissions
   - a. Greenhouse gases
     - global warming
   - b. Acid rain precursors
     - destruction of vegetation
     - loss of visibility
     - damage to buildings
   - c. Toxic chemicals
     - sickness and disability
   - d. Particulates
     - smog
     - sickness and disability
     - soot and filth
2. Water Emissions
   - a. Waste discharge
     - destruction of fisheries
     - illness
   - b. Thermal discharge
     - destruction of fisheries

38.

3. Solid Waste Generation
   - additional land use demands for disposal

4. a. Resource Utilization
   a. Water consumption
   b. Deforestation
      - erosion
      - loss of farm land
5. Site Impacts
   a. Aesthetic impacts
      - decrease value of nearby property
   b. Noise pollution
      - sickness and disability

II. ECONOMIC IMPLICATIONS OF ENVIRONMENTAL DAMAGES

A. Environmental damages = Real economic costs
Examples:
Health and Safety Impacts
- decrease worker productivity
- increase health care costs.

Destruction of Farm Land and Fisheries
- increase cost of food
- increase general inflation

Regional Degradation
- impacts health and safety of local population

B. Who pays these costs?
Costs are classified by whether or not the creator pays for them directly

1. Internal Costs
   - Those costs that are **directly** paid by the business concern.
   - Those cost are traditionally included in business analyzes.
   - Example, the cost of fuel to a manufacturer.

2. External Costs
   - Those costs which are indirectly paid by some other party as a result of the activities of others.
   - These costs are not traditionally included in business analyzes.
   - Example, the air emissions created when the manufacturer burns fuel affects the health of workers at other facilities resulting in decreased productivity.

3. Societal Costs
   - The summation of all internal and external costs.

C. How are external environmental costs paid?

1. Decreases in output by other businesses
   - Suffering decreased productivity due to sickness in work force.

2. Decrease in lifestyle
   - Illness
   - Higher costs of other goods and services

3. Paying to offset damages
   - Repairing building
   - Increased health costs
   - Increased use of fertilizers

D. Economic Implications

1. Decreased gross national product

2. Inflation

3. Higher taxes

4. Lower standard of living

III. RECOGNITION IN PLANNING AND OPERATIONS

A. Should Environmental Impacts be Recognized in Business Operation and Planning?

1. Failure to recognize environmental impacts will hinder the efficient allocation and utilization of scarce resources

2. Mis-allocation of resources will slow economic growth

B. How are Environmental Impacts Recognized in Market Economies?

Regulation and Taxation
- Used to internalize costs to the business which would otherwise be external so businesses will include them in their decision-making.

- 40

C. Taxation

Taxes are assigned to either the input resources (e.g., fuel) or the environmental loadings (e.g., tons of water discharged) of a manufacturing process.

This creates increases the internal (direct) cost of doing business, bringing it closer in line with the societal cost.

The closer internal and societal costs are brought together the more closely the business will utilize the resources in a more socially cost effective manner.

Taxation is also applied to the products (e.g., motor fuel) so the consumer sees a price closer to the societal cost and adjusts the demand for the product accordingly.

D. Regulation

Regulations dictate the manner in which a business is operated and planned.

Types of Regulation
- Permitting
- Rules
- Direct Oversight

1. Permitting

- Permits are required to discharge water and air emissions.

- Permits may place limits on the amount and quality of discharges.

- Permits may require that specific types of technologies are utilized, e.g., flue gas desulferization ("scrubbers") on coal burning facilities.

2. Rules and Regulations

- Mandate certain types of behavior

- Similar to laws, except issued by regulatory agencies within the limitations imposed by the legislature

3. Direct Oversight of Regulated Industries

- Certain vital industries occupy a market niche where effective market competition is not possible, e.g., electric utilities. Consequently, they are directly regulated to ensure operations and pricing are fair and efficient.

The planning and operations of these industries is subject to oversight and approval regulatory bodies. The extent of regulators influence in the business decision-making is determined by the laws establishing the regulatory structure.

42

ENERGY PRICING RECONNAISSANCE TRIP REPORT
ROMANIA - RMA/ROM-PR-01

APPENDIX B:
DRAFT BRIEFING PAPER ON ENERGY PRICING REFORM IN ROMANIA

Resource Management Associates of Madison, Inc.
Madison, Wisconsin, U.S.A.
April 23, 1991

- 43

Appendix B

Draft Briefing Paper on Energy Pricing Reform in Romania.

March 13, 1991

Romanian Counterpart Team
U.S.A.I.D. Energy Price Reform Project
Ministry of Resources and Industry
Bucharest, Romania.

Dear Colleagues:

Energy prices and quantities delivered have been centrally controlled in Romania for decades. This situation is now rapidly changing into a situation where energy prices will more accurately reflect both international market prices and/or actual costs. In addition, the quantities of energy consumed by various end users will no longer be centrally determined, but will be decided by the consumers themselves. A key piece of information for the consumer in deciding how much energy to purchase is the price of energy.

The prospect of paying international prices for energy may be terrifying, particularly at the adverse exchange rates now observed in the currency auctions, which recently are on the order of 200 Lei per dollar. At that exchange rate and a market based price for gasoline, the price of gasoline (without any taxes) would be on the order of 40 Lei per liter at current world oil prices. Fuel oil prices (#6) would be on the order of 29,000 Lei per ton. Electricity prices, based on Western European rates would be on the order of 8 Lei per KWH for very large industrial users and perhaps 16 Lei per KWH for small, residential users. These enormous price increases are greatly lessened by an exchange rate of, say, 60 or 100 Lei/dollar, but nevertheless, would still be quite high for Romanian users.

The purpose of the attached Briefing Paper is not, however, to speculate on the future levels of world energy prices and exchange rates, but rather, to explore the meaning of market based prices and the implications of these prices for energy users.

The Briefing Paper has been prepared by the RMA Energy Price Reform Team in Romania, part of U.S.A.I.D.'s Emergency Energy Program for Eastern Europe. We would like to use it as the basis for discussions with you regarding some of the issues raised by energy price reform in the context of Romania's move to a market economy.

The Briefing Paper includes a number of economic issues to which we have devoted much thought; but, of course, it does not reflect the same level of understanding of the Romanian economy as you yourselves already have. Please accept it as a contribution to your economic debate, and the basis for a mutual exchange of ideas in our working sessions.

Sincerely,

Mark Hanson
Team Leader

U.S.A.I.D. EMERGENCY ENERGY PROGRAM
BRIEFING PAPER:
ENERGY PRICE REFORM IN ROMANIA

The initial objective of energy price reform in Romania is to move energy prices closer to market-based price levels. The other principal objective is to create competitive conditions where possible. Where competitive conditions are created, it should be possible to decontrol prices. Where such conditions cannot be achieved, continued price regulation will be necessary. This briefing paper explores a number of issues related to the pricing of energy in both competitive and regulated industries. We address the following issues:

(1) Determining Market-based Prices for Energy

Privatization and Competition in Energy Production

(2) Responses of Firms to Market-based Energy Prices

(3) Pricing Electricity: Long-run Marginal Costs vs. Actual "Accounting" Costs

Automatic Price Adjustment Mechanisms for Electricity

Electricity Rate Design Should Reflect the Underlying Cost Structure

Other "Public Utilities" Similar to Electric Power

(4) Energy Regulation and Private Power

(5) Qualifications and Limitations

Taking Environmental Costs Into Account

The Social and Economic Effects of Rapid Price Changes

The Use of New Price-setting Procedures to Provide Financial Incentives to Competitive Enterprises

These issues are addressed in the following pages. The comments are intended to initiate a discussion with our counterparts in Romania. Out of this discussion, and the subsequent "scenario development" work which is a part of our Energy Price Reform task, we hope that useful ideas will emerge for the guidance of energy pricing policy in Romania.

(1) Determining Market-based Prices for Energy

In a country in which prices have had little relationship to market-based prices, it is no easy task to define or measure market prices or economic cost levels. Where there have been shortages, it is not clear what prices will equate supply and demand. Furthermore, some observed prices are affected by subsidies and taxes. Finally, there is a problem of circularity - the price of product A depends on the price of input product B which in turn depends on the price of input product A.

For internationally traded energy commodities, world market prices or border prices provide a yardstick. This procedure requires an actual or estimated market exchange rate between the local currency and foreign currencies. We can develop some idea of market prices in this manner.

The argument for using these prices in the situation of the move to a convertible currency and open markets is that Romanian producers of energy will have to compete with the suppliers of energy who would be willing to supply energy at these prices. In cases where Romanian providers could not compete, it would, with a convertible currency, be less costly for energy consumers and the economy to import energy.

The relationship between dollar (world market) prices for energy commodities, lei prices for energy commodities, and the lei prices of other (non-energy) goods and services in the economy is complicated. Currently, it is possible, for example, to have a large disparity between the dollar and lei prices of energy commodities, but for the relative lei prices of energy commodities and other goods and services to be quite reasonable. It is only as lei become fully convertible (i.e. as a market exchange rate becomes determined) that the use of dollar prices will be fully appropriate.

The relative lei prices of energy commodities and other goods and services has another significance in an economy with inflation. (For this purpose, inflation is defined as the average price increase in the Romanian economy. This can be measured approximately by the new index of consumer prices issued by the Romanian statistical commission.) To maintain "real" or relative energy prices constant, let alone increase them, it is necessary to increase them by as much as the general increase in prices. The statistical commission has reported that consumer prices have risen by 50% since November 1, 1990 (when the first major decontrol of prices occurred). Thus, energy prices, which have remained controlled, would have to rise by 50% to maintain the same "real" level. The use of world market prices should take this consideration into account, since, ceteris paribus, the dollar exchange rate of lei should fall as general prices rise.

In Romania the introduction of foreign exchange auctions has confirmed the fact that the market exchange rate is considerably lower than the pre-April 1, 1991 official rate of 35 lei/dollar, or the new exchange rate of 60 lei/dollar. More categories of purchasers of dollars will be allowed to participate in the auctions. We understand, however, that the government intends to use the new official rate, not the new currency auction rates, as the rate at which imported energy prices will be converted to lei. We propose to use the new rate as a baseline rate to use in our analysis; alternative rates

could also be considered for analytical purposes, for example 90 lei/dollar.

The principal internationally traded energy commodity is crude oil. Romanian domestic supplies peaked in 1976, and Romania now imports two thirds of its crude oil requirements. As of January 1991, oil imported from the Soviet Union has to be paid for in convertible currencies. Another major source is Iran. Imported oil can be priced at actual delivered contract prices.

Oil products such as distillate and residual fuel oil and gasoline can also be priced at delivered import prices. Natural gas too can be priced at European prices, based on deliveries from the Soviet Union or other potential sources.

Bituminous coal can be priced at delivered import prices. Romania's coal resources, which consist mostly of lignite, are not readily traded internationally owing to lignite's low energy content per unit of weight, and its high sulfur content. The use of actual Romanian accounting-based costs as a starting point may provide too low an estimate, however, as Romanian supplies are limited. The sulfur and other emissions from burning lignite in power plants also suggest that a low price would give the wrong price signal to the planners at RENEL, the Romanian electricity company. (We will discuss below the introduction of pollution costs into energy planning.)

The pricing of electricity produced from Romanian lignite is an instance in which the use of long-run marginal costs should be considered - an issue which we will take up later.

Nuclear fuel costs include the cost of uranium mining and milling, conversion, enrichment, fabrication into fuel assemblies, and certain other incidental costs such as transportation, storage and insurance. Enriched uranium, which includes the first three items, represents the greater part of the total, and can be priced at world market prices. Fabrication of the fuel assemblies, and the incidental cost items, can be added, based on actual or estimated costs for Romania's Candu reactors.

There are other fuels which are perhaps of sufficient magnitude to be taken into account, such as fuelwood. Perhaps we can be guided by actual market prices here.

Privatization and Competition in Energy Production

The Romanian government, as part of the current economic reforms, has begun to decontrol competitive industries effective November 1, 1990. The food, energy and raw materials sectors were not included; competitive enterprises in these sectors are to be decontrolled later. These reforms create the conditions in which enterprises should be able to operate with greater incentives and more flexibility.

The government is also breaking up government enterprises by restructuring them into autonomous bodies and commercial firms. As we speak, these changes are under way. In the energy sector, the supply of fuels is generally not a natural monopoly, and

from an economic point of view, decontrol should be beneficial.[4] This would require the establishment of a number of enterprises in each "market" in order to ensure competition. A market can be defined in terms of one or more products that are close competitors within a certain geographic area.

Oil and gas exploration, development and production - provided there is equal access to pipeline networks - allow for plenty of competition. Coal markets may in many cases also allow for competition, depending on the minimum economic size of coal mining operations, coal quality differences, and transportation cost considerations.

Petroleum refining, given that there are some ten refineries in Romania and that both crude oil inputs and product outputs of refineries are internationally traded, also allows for competition.

(2) Responses of Firms to Market-based Energy Prices

To explore the effects of market-based pricing, we can develop "scenarios" or projections to test out the effects of different price levels, based on alternative assumptions about the levels of market-based prices, and how suppliers and consumers will respond to price changes. By "consumers" we mean both the residential population and industries. The two main aims of market pricing, it will be recalled, are to send appropriate prices signals to consumers on the one hand and to suppliers on the other.

The residential population accounts for a small percentage of energy use in Romania - perhaps 10%, much less than in many other countries. This makes market pricing somewhat less important for these consumers. However, their use of energy is said to be growing, and it is important that their tariffs not be set at such low levels that they have little incentive to use energy wisely. Residential consumers have extremely low gas, electricity and district heating tariffs at the present time. Bearing in mind that distribution costs are higher for small users, it would be desirable to increase prices closer to market levels. To avoid adverse social effects, a low "lifeline" rate could be maintained for a minimum KWH use corresponding to the provision of essential lighting and other requirements; for additional use, a full rate corresponding with long-run marginal cost could be applied.[5]

The most dramatic effects of market pricing of energy may come in the industrial sectors. How firms respond to the dramatically increased price levels that would result in either cost based or world market energy prices depends on a number of factors in addition to the new prices. The least response would occur if no other adjustments to market conditions were in place. In this case, each user of energy would face a higher price for energy requirements and would in turn pass on the higher cost in the form of

---

[4]We understand that the government is taking into account other factors such as national security in its determination of ownership options for energy supplies.

[5]Gasoline prices are currently set in this manner. It is easier to apply a two-step tariff to electricity.

higher prices for products.

If however, incentives were put into place whereby energy savings which would reduce energy costs and some type of reward were to occur to managers and/or workers who brought about the energy savings, then energy and product costs would increase less than in the case of no adjustments. Depending how easily energy reductions could be put into place, overall energy costs might even decline as a result of the incentive system. Establishing fair, efficient, and effective rewards is a complex task. To avoid all of the complications involved in establishing a reward system, a free market system could theoretically be adopted which would leave decisions on rewards up to the owners of the plants (which might include the workers) and their managers.

Within a free market system where not only energy prices, but all commodities, services, and even labor, are provided at market prices, the firm (in theory) will purchase all inputs, including energy only to the degree necessary. Furthermore, the firm will actively pursue conservation or energy efficiency measures to the point where the last Lei invested in conservation in the factory will result in the same return as the last Lei spent on other investments or other inputs, such as energy. The incentive for this behavior which minimizes all costs is that it will maximize profits for plant owners. In cases where market imperfections exist, this implies the opportunity to maximize excess profits. Under perfectly competitive conditions, this implies that the firm will be able to survive, pay workers and managers, and provide sufficient profits to plant owners (workers, managers, outsiders etc.), to justify their investment in this particular plant. **The greatest response to energy price increases will occur under these conditions.**

In practical terms, what this means for a given firm may vary considerably from firm to firm. To provide a comprehensive review of the potential responses is probably impossible. However, it is instructive to consider two hypothetical situations, one in the power industry and the other an industrial plant.

District Heating Plant

District heating plants in Romania are common and typically produce power, steam, and hot water for residential and sometimes industrial users. In at least some of these plants, there is difficulty in meeting all customer needs due to problems of fuel availability and maintenance, which may be aggravated by the fuel quality that has been available.

With a shift to world energy prices, energy input costs of plant operation would increase dramatically. If revenues to the plant are sufficient, however, the plant would be able to obtain sufficient energy supplies. The high cost of energy would evoke both short term and long term responses. In the short run, any cost effective measures to reduce energy losses would be undertaken. For example, this might involve the repair of pre-heaters, increased insulation of steam and hot water lines, increased maintenance of steam lines, boiler tuning, etc. In the long run, depending on the age of the boilers, and their need for overhaul, it is possible that fuel substitution would become appropriate. While this would be quite capital intensive, the cost differential between fuel oil or

natural gas and coal is so large that it may be justified to install a coal boiler (with pollution controls) to reduce overall plant costs.

Alternatively, depending on the solid waste situation, it may be cost effective to utilize fluidized bed technology and burn municipal waste, as is common in Switzerland and Germany.

Industrial Plant - Paper Mill

The responses in a paper mill to changes in energy prices would be somewhat similar to those for the district heating plant. Because the energy cost component of the paper mills is a much lower percentage than that for the district heating plant, the types of measures undertaken to reduce energy costs may be somewhat different.

In the short run there would be various maintenance issues to bring the mill up to top efficiency. In the longer term, process changes and other capital-intensive modifications would likely be justified. For example, it could be appropriate to introduce a much higher level of heat recovery (using heat exchangers) from the numerous waste flows at the mill. Depending on the cost of the wood raw material, the types of wood waste (if any), and the type of paper being produced, it could be cost effective to install a new boiler which would have dual fuel capability to burn wood and/or natural gas.

What is evident from these two hypothetical cases is that the introduction of world energy prices could result in considerable changes. These changes range from lower cost measures, which could be implemented fairly quickly, to longer term measures which might significantly alter the fuel balance in Romania away from oil and gas which on the world market are expensive fuels. These changes would be the result of the change in prices, the introduction of some new technologies as the Romanian economy is opened up to technologies available on the global market, and the impacts of incentives to make these changes due to the need to compete (and profit) in the market place.

It is also possible that some plants can not survive in the market place because energy costs will be too high. These will be industries where energy use is very high and where Romanian firms will have to compete with firms in other countries that do not have to face world market prices for energy (or other inputs). Aluminum production is one example. This industry is dominated by firms that have captive hydropower or hydropower from state owned utilities. The importance of power cost to this industry is highlighted by the fact that plants are moving from some regions with considerable hydropower and attractive power rates (e.g. the Northwestern U.S.) to other regions (Amazon Basin in South America) and locations in Africa, where hydropower rates are even lower.

(3) Pricing Electricity: Long-run Marginal Costs vs. Actual "Accounting" Costs

Certain energy suppliers, including all or part of the electricity industry, are likely to remain natural or de facto monopolies[6] in Romania. For such firms, the major problem with using world market prices or equivalent current lei prices for energy pricing and planning purposes relates to divergences between current or "accounting" costs and long-run marginal costs. The issue is highly important because pricing should in general reflect not only current costs but future costs, such as new investment costs, that may be incurred. As noted above, this problem arises with respect to non-traded items such as lignite, as well as electricity, as will be discussed below, even though electricity is traded internationally.

The classic example of the need to use long-run marginal costs relates to pricing the use of a bridge for automobile traffic. Once the bridge has been built, its cost is "sunk cost" and from a strict economic point of view, its use should be free, since the short-run marginal cost is zero. (Of course, as a practical matter a toll may need to be charged to recover the cost to the public authority of financing the construction.) But consider the price "signal" that the users are getting, if the price is set at zero. With no charge, consumers will tend to increase their usage, and eventually may approach the maximum capacity of the bridge, resulting in the economic cost of congestion delays or, ultimately, the cost of a new bridge.

In anticipation of this situation, a "full" price can reasonably be set to include the cost of a new bridge, which is the long-run marginal cost. By charging users this full price, they would be getting the right price "signal" regarding the costs incurred by their usage.

Now consider a very similar example in the energy market. Existing hydro-electric facilities cost very little to operate - most of their cost is "sunk" cost. But if their output is charged at a very low rate, it will encourage consumers to increase their usage, which in turn will require the construction of expensive new electric energy facilities.

One solution to this problem lies in the use of long run marginal costs for electricity pricing in particular. The calculation of long run marginal costs can be complicated, and there have been many methods used to estimate them for the United States electrical generating system, for example. One method is to measure such costs from the full costs (investment costs as well as fuel and other operating costs) of the most economical new source of electrical energy.

For Romania, there are at least two candidate sources of "new" electricity supply, after certain coal-fired and hydroelectric plants currently under construction have been completed. Probably the most economical one is the increased output and capacity which could be obtained from better maintenance and repair of existing coal-fired

---

[6]A de facto monopoly would exist in an industry with less than three firms, even though the industry is not a natural monopoly.

generating units. This might provide a low estimate of marginal cost. Whether it is a good estimate would depend on the period for which this source is sufficient to provide for Romania's electricity requirements. We don't know the answer to that question at this time.

If we assume that additional electric generating capacity will be required in the foreseeable future to meet Romania's electricity requirements, the next source of electricity in practice is likely to be the first Candu nuclear reactor.

Five 750MW nuclear units are under construction or planned at Cernavoda in south-eastern Romania near the Black Sea. We do not know the exact status of these units; we understand, however, that the reactor has been installed in Unit One and General Electric turbines have been installed in Units One to Three. We also understand that Unit One is scheduled for service in 1994. An additional site has also been tentatively identified for further nuclear units.

In order to calculate the cost of nuclear power, the construction cost of Cernavoda Unit One will need to be estimated, and converted into a per-KWH "fixed charge" based on reasonable assumptions about finance costs, capacity factor, and life of the unit. Addition per-KWH costs include nuclear fuel costs, and other operating and maintenance costs. Nuclear fuel cost should be relatively low, but construction costs will be high.

There are, then, at least two new sources of electricity which could be used to estimate marginal electricity costs in Romania. The first is electricity from the additional capacity which would be created by repairing and maintaining existing generating units which are out of service or operating below full availability or reliability levels. The costs of this source include the costs of new investments to get the plants running properly, and the ongoing fuel costs (coal) and other operating and maintenance costs.

The other source is nuclear power from the first Candu unit, including the fixed cost of investment in the plant and the investment in transmission facilities to bring the power to market, and ongoing nuclear fuel and other operating and maintenance cost. In the case of a nuclear unit, it is also necessary to take into account "capital additions" (additional capital investments during the life of the plant) and to make provisions for disposing of the radioactive nuclear waste and decommissioning the reactor at the end of its useful life

Electricity is an internationally traded commodity in Eastern Europe. From a short-run marginal cost standpoint, it is economical to operate the existing electricity system in Romania in such a manner as to minimize short-run fuel and other variable operating and maintenance costs, and to purchase imported electricity if the cost is less than the domestic short-run marginal cost. (Likewise, it is economical to export electricity if the reverse situation is true.) However, the long period required to plan additional new generating units necessitates the use of long-run marginal costs in

planning new units, in contrast to minimizing the operating costs of existing units.[7]

There are, however, a number of considerations which suggest that world prices might not always be appropriate prices to use in Romania. The costs of producing electricity (and possibly certain other energy commodities) in Romania may be less than in other countries, in part due to lower wage rates and higher efficiencies in some energy conversions. If this is the case and if there are some barriers to imports and exports for lack of adequate transmission lines etc., an argument can be made that certain energy prices should be set to cover only actual "accounting" costs.

Prices that cover actual costs should, by definition, provide sufficient revenues to cover the expenses of the industry. This level of costs should not require any subsidies because, in a free market economy at equilibrium, energy prices include a normal profit (sufficient profit to provide a necessary return on capital to justify the capital investment on the part of investors).

Thus, cost based prices would provide for normal profits while world prices would actually provide excess profits. This raises important policy questions. With prices based on actual costs, do consumers have sufficient incentive to conserve energy resources economically? Also, would sufficient incentive exist for the firm to make new investments, if prices are based on actual costs? If world prices are used (and the excess profits can be retained by the firm), an incentive would exist to increase production either through expansion of existing firms or through the addition of new firms to the market. If the country imported energy, such expansion would serve to reduce the level of energy imports while if the country were an energy exporter, the increase in energy production would permit further increase in exports.

There will be some complicating factors in this analysis. For example, the production of district heating (hot water for building heating) and steam for industrial process use raises the issue of allocating costs between the electric and thermal output.[8]

---

[7]The overall economic objective for regulated or mixed industries is usually stated as "least cost integrated planning" (LCIP). This requires that a reliable level of service should be provided at the lowest reasonable cost to society. Cost should include environmental effects of the service, as discussed below. "Integrated" means that investments in energy conservation should be made up to the point at which the marginal cost of a KWH saved is equal to the marginal cost of a KWH produced.

[8]One solution to this cost allocation problem is to allocate to electricity production those capital costs (construction costs multiplied by a fixed charge factor representing financial costs, amortization, etc.) and fuel and other operating and maintenance costs which would be incurred if the plant were designed and operated for electricity production only. The additional capital costs and fuel and other operating and maintenance costs incurred to run the plant as a cogeneration facility would then be allocated to the thermal output.

Automatic Price Adjustment Mechanisms for Electricity

Energy price reform in Romania is taking place within the context of general price decontrol. It is important for energy prices to be able to adjust for general inflation in the economy, and to increase by a larger amount than general inflation in order to move towards market prices.

This problem is particularly serious for the electricity sector, which has tariffs that are difficult to change quickly, but which depends on fuel purchases which can have rapid price increases.

An automatic fuel adjustment clause provides a mechanism for quickly passing increases in fuel costs through to consumers.

Electricity Rate Design Should Reflect the Underlying Cost Structure

This paper will not develop the issues in rate design which are obviously important in making the prices of electric service reflect the underlying costs. Suffice it to say here that rate design typically takes into account actual accounting costs. The use of long-run marginal cost based rates should be encouraged; at a minimum, rate design can be influenced by marginal cost considerations as well as accounting costs.

Secondly, tariff design can take into account voltage level of service, load factor, time of use, and different reliability levels, etc., all of which affect costs.

Other "Public Utilities" Similar to Electric Power

The reason for treating the transmission and local distribution - and possible the generation - of electricity differently from the energy fuels is the existence of a natural monopoly.

Certain other energy industries are also characterized as natural monopolies. In particular, the pipeline systems for natural gas and oil are unlikely to be sufficiently competitive to allow for competition. And the railway network for coal transportation is the same.

(4) Energy Regulation and Private Power

Where there is insufficient competition in a market, for example when there are fewer than three firms in the market, some means must be found to regulate prices in the public interest, to avoid unjustified increases of prices.

The traditional means of regulation of such "natural monopolies" as electric utility companies in the United States, for example, is based on allowing the firms to set prices equal to their current costs plus a cost of capital invested. The capital cost is equal to the sum of (1) depreciation expense of the capital equipment and (2) the cost rate or "interest rate" for capital multiplied by the amount of the investment. The annual

depreciation expense is usually simply the initial cost of the plant and equipment divided by the expected useful economic life of the plant and equipment; depreciation on each item or group of items is calculated separately based on the particular depreciation rate. The amount of the investment in each year is equal to the original investment cost less accumulated depreciation to date; this is called "net book value."

This procedure provides a reasonable starting point for discussion of regulatory pricing. Critics of the procedure say that it gives the firm no incentive to reduce costs because they can always be passed along, and it is true that many inefficiencies are allowed. However, government regulators can "audit" the books of the firm to ensure that there is no fraud, and they also require the firm to show that its plans and operations are reasonably efficient.

The outcome is a system that can work reasonably well, although there have also been significant problems. Perhaps the most salient problem in the United States has been that the firms built too much generating capacity (particularly nuclear power plants), being less careful than a firm in a non-regulated market would have been to make sure that the capacity was needed and that it was not too expensive.

There are several different models for non-competitive markets. In the United States there have been several models. First, there are the large number of regulated, privately-owned companies that provide most of the electricity in the country. They are regulated in the manner outlined above, mostly by regulatory commissions which have been established in almost all of the 50 states. The owners attempt to increase profits, while the commissions resist rate increases above the levels necessary to earn their "interest rate" which is called the "cost of capital" or a "fair rate of return" on the capital invested.

The companies earn sufficient profits to cover their investments, but are not allowed to earn excess profits. It is sometimes necessary for commissions to provide additional incentives for desired investments, or to order the companies to make them. The commissions also review the operating efficiency of the companies, and their investment plans, to see that they are keeping costs as low as reasonably possible. However, the commissions do not attempt to manage the companies. It is the managers' job to manage, and the commission will only review the management decisions. In practice, the commissions are hampered by the difficulty of fully scrutinizing the practices of the companies.

A second common model is the "public power" model which has two types. There are "rural electric cooperatives" which are owned by their members (farmers and others); and there are "municipal utilities" which are sometimes part of a town government or may be separate authorities. The largest of these is the Los Angeles Department of Water and Power. In each case, these public power systems are under democratic control by their members or the voters in their districts. The dispersion of ultimate authority across the whole local population has weakened the democratic controls that, in theory, are very strong.

The new model which is being fostered in the United States today is the "independent power" or "private power" company. Small and medium-sized power plants are being built by independent companies, and the large regulated companies are being forced by the commissions to buy power at rates equal to the marginal cost of generating power on the large company's own system. In this manner, it is hoped that competition will be created and the generation of power can be deregulated.

This raises an important point about the structure of the electricity industry. It consists of three levels - generation, transmission and local distribution. There is a movement in such countries as the United Kingdom and the United States towards decontrol of prices, as generation becomes sufficiently competitive. However, transmission and local distribution are "natural monopolies" (it is uneconomical to have more than one firm providing the service in a particular area.) These levels will require continuing regulation. It is therefore only the generation of electricity that will likely be decontrolled.

(5) Qualifications and Limitations

Taking Environmental Costs Into Account

For some fuels such as lignite and high sulfur fuel oil, the environmental effects are so significant that even in the initial stages of price reform it may be worth taking them into account. (Indeed, the burning of all fuels affects the environment, and the true economic costs of such effects should be taken into account in the long term.)

For purposes of this analysis, we can assign physical pollution coefficients to electric energy generation from each specific fuel. The amounts of SO2 emitted can be estimated, for example. Monetary costs can also be estimated, based on the costs of remediation or the estimated health and other costs of the emissions. At this stage, any estimates developed will obviously be very preliminary. Nevertheless, if environmental costs are included in the costs of electricity generation from alternative fuels such as coal, oil and gas, the choice of fuels could be affected. If pollution damage and/or control costs are included, the cost of electricity will be increased.

The Social and Economic Effects of Rapid Price Changes

There are obviously serious concerns regarding the speed or completeness with which energy prices should be adjusted. It is a major political decision how quickly and even how fully prices should be changed to correspond with market-based prices.

From an economic standpoint, the more quickly consumers receive a clear price signal about the costs of their usage, the more quickly they will have the opportunity to respond in an economical fashion. For purposes of this analysis, we assume that there are overall economic advantages to such adjustments. The objective of sending the appropriate price signal to consumers is give each consumer an incentive to set his or her consumption at the level at which he or she is willing to pay the true cost of energy to society.

For industrial consumers of energy, there is the choice of which products to produce, how much to produce, and what techniques to use in production. In energy-intensive industries, these decisions will be influenced by the prices that have to be paid for energy inputs. It must be expected that if energy prices are increased significantly, the production of some products may be affected. Among these are the aluminum and steel industries, for example. Certain products may no longer be economical in the same amount, or perhaps at all, which could have major impacts on the overall economy. New techniques may be necessary which use less energy.

The Use of New Price-setting Procedures to Provide Financial Incentives to Competitive Enterprises

Finally, we need to revisit the reasons for price reform and the way in which prices are set. So far, we have emphasized the need for prices to reflect input costs, and have considered the use of pricing based on long-run marginal costs. Prices so determined will send out the correct price signals to purchases of the product.

But what about incentives for the suppliers themselves? We have not fully considered the more complex pricing issue regarding deviations of market prices from input costs in order to increase a firm's "profit." We use the term "profit" here simply to mean the difference between sales revenues and the costs of materials, labor and all other inputs, including the interest cost on borrowed capital. What remains is the firm's profit or net income.[9]

We have assumed that the first priority in Romania is to set prices closer to true cost levels. The second, or a parallel, step can be to allow enterprises to increase their profits by, for example, reducing their costs by greater productivity, and retaining the profits that result. This would be appropriate, we believe, in competitive sectors. (Competitive industries have been defined in the new Romanian market economy legislation as those in which there are three or more firms.)

A "normal" rate of return on capital is the rate of return which is comparable to that earned in other investments involving the same level of risk. The investor is always trying to increase his or her level of return above the normal rate; and of course is trying to make sure that the return does not fall below the normal rate. The importance of allowing profit levels to vary according to each firm's success in reducing costs (and/or of course finding new markets) is to create a very strong incentive to the owner/managers to ceaselessly attempt to improve productivity and to seek out new markets in which the firm can earn greater profits. The lack of such incentives in the Romanian economy is a major obstacle which the reforms are aimed at addressing. Such incentives will ensure that the Romanian economy will respond more rapidly to the economic challenges it is facing.

Resource Management Associates/ Tellus Institute
Bucharest, Romania, March 12, 1991

---

[9]If there are taxes on profits, net income after tax is equal to net income before tax minus taxes; this paper does not go into tax issues.

Electric Utility Least-Cost Planning

Making It Work within a Multiattribute Decision-Making Framework

Mark Hanson, Stephen Kidwell, Dennis Ray, and Rodney Stevenson

Least-cost planning is transforming the planning process traditionally used in the electric utility industry. As compared to the traditional planning process, least-cost planning broadens the participation by multiple parties and widens the range of the planning options that are assessed. Its integrative nature opens consideration of multiple planning objectives (such as social, environmental, and economic objectives) in evaluating demand-side and supply-side options. Economic rationales for least-cost planning are found in neoclassical and institutional economic thought. Multiattribute decision analysis provides an analytical and decision-making framework for least-cost planning; it can be used to identify issues, objectives, preferences, and expected consequences of planning options.

Hanson, Ray, and Stevenson are with the University of Wisconsin-Madison. Kidwell is with Union Electric, St. Louis, Missouri.

Journal of the American Planning Association, Vol. 57, No. 1, Winter 1991. © American Planning Association, Chicago, IL.

Before the 1970s, the traditional planning process used by electric utilities seemed to work well. Growing power demands were met by electric utilities in a timely fashion. The planning process for the growth in electric supply was led by the utilities, subject to regulatory approval. Electric power planning was thought to be relatively easy because demand growth was quite predictable, construction times for new power plants were relatively short, and environmental constraints were minimal. In the 1970s, however, the life of an electric power planner became much more difficult. Future demand growth became much less certain. Construction lead-times grew longer as utilities began building larger generating units. The regulatory review process became more contentious as intervenor groups raised concerns about over-construction of generation capability, rising energy prices, unmet social needs, and declining environmental quality.

Beginning in the late 1970s, Roger Sant, Amory Lovins, and other critics of the traditional planning process began advocating a new approach that would evolve into least-cost planning (Sant 1979; Sant et al. 1984; Naill and Sant 1984; Lovins 1976). Since then, interest in and use of least-cost planning by utilities and regulators has spread to the point that it has now been adopted in various forms by most state public utility regulatory agencies.[1] Least-cost planning principles are embodied in what Gellings et al. (1987) call "integrated resource planning" and others call "integrated least-cost planning." We use the phrase "least-cost planning" synonymously with those terms.

Although traditional and least-cost planning broadly fall under the rational planning model, their differences are marked. As compared to the traditional planning process, least-cost planning develops a more complete set of demand and supply options, encompasses a wider set of objectives, and involves the participation of a broader range of parties and interests. Those differences have major implications for the electric utility planning process, for planning techniques, and for the outcomes of the process. In particular, both the numerous parties and the multiple objectives considered in least-cost planning suggest that a formal multiobjective technique may facilitate the planning process. Furthermore, the common planning approaches and problems shared by electric utility least-cost planners and urban and regional planners suggest that formal, multiobjective planning techniques should be considered more often in conventional planning settings.

Our purpose in this article is to describe and discuss the significant (yet neither well defined nor understood) evolutionary trend toward least-cost planning in the electric utility industry. We first clarify basic least-cost planning concepts by comparing least-cost planning to the traditional electric utility planning approach. Next, we relate least-cost planning to two broad streams of economic thought that have been the theoretical basis for decision making in traditional electric utility planning—neoclassical and institutional economics. Finally, we report on the results of a case study in least-

59

cost planning involving a major electric utility. With this study we illustrate how multiattribute decision analysis can be used to facilitate the least-cost planning process.

Traditional Electric Utility Planning

Traditionally, an electric utility's approach to planning was to determine the generation-capacity expansion plan that would ensure that the utility could reliably supply the forecasted electrical demand at a reasonable supply cost. Supply cost is an important consideration because electric power technologies are capital-intensive. Consequently, accommodating demand growth requires considerable capital investment. For example, without substantial adoption of demand-side options by utility customers, e.g., high-efficiency lighting and motors, cogeneration, building energy management systems, and industrial process improvements, new generating capacity needs in the United States from 1989 to 2000 could amount to 125,000 megawatts (which is about 19 percent of current capacity) and require investment of $158 billion (in 1988 dollars) during that period (*Electrical World* 1988).

Electric utilities and state regulatory agencies have played dominant roles in the traditional approach to electric utility planning. Under the traditional approach, a utility (1) forecasts demand; (2) screens supply-side options according to its own economic and financial objectives as well as its engineering and environmental constraints; (3) conducts detailed analyses of selected supply-side options; and (4) requests a certificate of public convenience and necessity from the appropriate regulatory agency (typically a state regulatory commission) for its chosen option. In response to the utility's request, the commission evaluates the reasonableness of the utility's proposal by inquiring about the future demand for electricity, and then considers three threshold questions:

1. Is the proposed plant needed to provide sufficient capacity to maintain adequate supply reliability?
2. Are the technological aspects of the proposal sound?
3. Is the construction plan financially feasible?

Under the traditional approach to utility planning, summarized in Figure 1, the commission does not attempt to identify the best projects; it seeks only to determine if the proposed project is satisfactory. As a consequence, if the answer to each of the threshold questions is yes, the project is approved.

This traditional electrical power planning process has several shortcomings. First, traditional electric utility planning is supply-side-dominated in that the utility is not required to give equal consideration to supply-side and demand-side options. Second, the traditional planning process limits the criteria for project evaluation; generally it focuses on traditional financial and economic considerations. This occurs because the utility's selection criteria reflect private interests rather than social interests and because regulators consider only the utility's specific

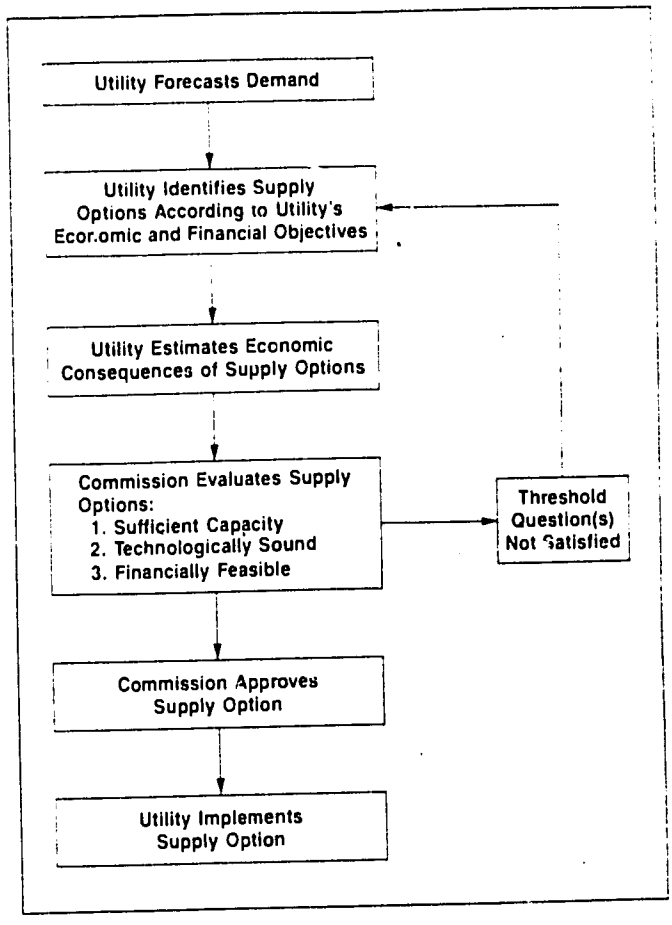


FIGURE 1: Traditional electric utility planning.

proposal rather than pursuing a comprehensive plan for meeting energy needs over time. A final shortcoming is the restriction the traditional process places on the range of participating parties. Intervenors who may be concerned about regional energy needs, environmental quality, or social issues find it difficult to become involved, particularly in the early stages of planning. Recognition of these shortcomings has given rise to the pursuit of the least-cost planning alternative.

Least-Cost Planning

During the 1970s, electric utility industry planning processes and techniques changed. Some commissions (such as those of California, New York, and Wisconsin) started requiring utilities to file advance plans. In an advance plan process, a utility presents its long-term power supply plan to a regulatory commission. Rather than presenting the commission with a single project, the utility provides a set of anticipated future projects together with the alternatives that were considered in developing the plan. With advance planning, the commission's role extends beyond granting approval for a specific project to evaluating and modifying the basic plan that underlies project selection. Thus, regulatory focus shifts and regulatory commissions become more deeply involved in

60

planning areas traditionally viewed as the prerogative of utility management.

As commissions and intervenors became more involved in planning through the advance plan process, and as the conditions of the electric utility industry changed, the objectives of electric utility planning broadened, and planning options increased. These changes were consistent with least-cost planning principles.

Least-cost planning encompasses both the use of alternative supply sources (that is, supply-side options), and modifications in the use of energy (that is, demand-side options). Electric power supply options include both a variety of supply technologies and different types of supplying entities. Electric power supply technologies can be distinguished by method of production (steam-generation, hydro, combustion turbine); by fuel type (nuclear, coal, oil, natural gas, refuse-derived fuel, and so forth); and by the intended type of use (base-load, cycling, or peaking). Alternative ownership arrangements for power supply facilities include utility ownership, independent ownership, and customer ownership.

Demand-side options are technologically based or behaviorally based programs that modify the amount or time of energy use. Demand-side options for electricity and other energy forms include attic or water heater insulation; high-efficiency motors, lights, ballasts, and furnaces; timers on water heaters; direct-load control equipment; time-of-use pricing; interruptible service; and business work hours and manufacturing shifts.

A central goal of least-cost planning is to provide energy services at minimum cost using demand and supply options. Minimizing the cost of energy services (such as heating, lighting, and mechanical drive in manufacturing processes) extends beyond achieving the lowest cost for power supply; meeting energy requirements efficiently requires attention to economic, environmental, and social effects. Thus, the intent of least-cost planning is to consider all relevant factors explicitly, and to balance competing interests to determine the method for meeting energy requirements. As noted in a Wisconsin Public Service Commission order (1986):

> The value of least-cost integrated planning lies in its explicit consideration of values and of ways of meeting load which have been present but not articulated in "classic" utility planning . . . and in its integration of those factors into a comprehensive plan.

The emergence of least-cost planning is bringing about fundamental changes in the electric utility planning process. Table 1 summarizes these changes by comparing features of traditional and least-cost planning. In our view, a significant feature of least-cost planning is its function as a planning process rather than only as a planning technique. That process encompasses a broader range of participants, a larger set of objectives, and a more diverse set of options than does traditional electric utility planning. Its purposes are more robust than developing techniques to compare the direct cost of specific demand-side and supply-side options. In least-cost planning, the way that decisions are made and the people who make the decisions are of significance.

TABLE 1: Features of traditional and least-cost planning

Feature	Traditional planning	Least-cost planning
Options	Supply options	Demand and supply options
Focus of economic cost analysis	Rate-payers	Multiple groups (society program participants, rate-payers, individuals, etc.)
Objectives	Single	Multiple
Environmental quality	Meet minimum requirements	Improve quality beyond minimum levels
Judgment	Implicit	Explicit
Preferences	Implicit	Explicit
Reliability	Meet traditional standards	Choose appropriate reliability level
Role of public groups	Intervenors	Participants

An important difference between the least-cost and traditional processes is the involvement of the public and of various interested parties in all stages of the planning process. Under least-cost planning, as shown in Figure 2, different parties have the opportunity to propose and evaluate options from the perspective of their explicitly stated preferences. Differences in these values and outcomes must then be negotiated or mediated in the regulatory decision-making process. The major planning focus is placed on the development of an advance plan that is an integrated, long-term (e.g., 20-year) plan to meet the energy service needs of end-users in an efficient manner. Advance plans are undertaken periodically to make the planning process iterative and to provide feedback to planners about their demand forecasts, evaluation of least-cost options, and determination of likely consequences of the chosen plan.

Rationales for Least-Cost Planning

If least-cost planning is to become the dominant planning process in the electric utility industry, its rationales need to be firmly established and, indeed, they should demonstrate least-cost planning to be superior to traditional planning. Rationales for least-cost planning should encompass (1) the appropriateness of integrating consideration of demand-side and supply-side options; (2) the value of explicit consideration of other social and environmental objectives; and (3) the desirability of greater public participation in the planning process. Rationales for least-cost planning emerge from both neoclassical and institutional economics perspectives.

-61-

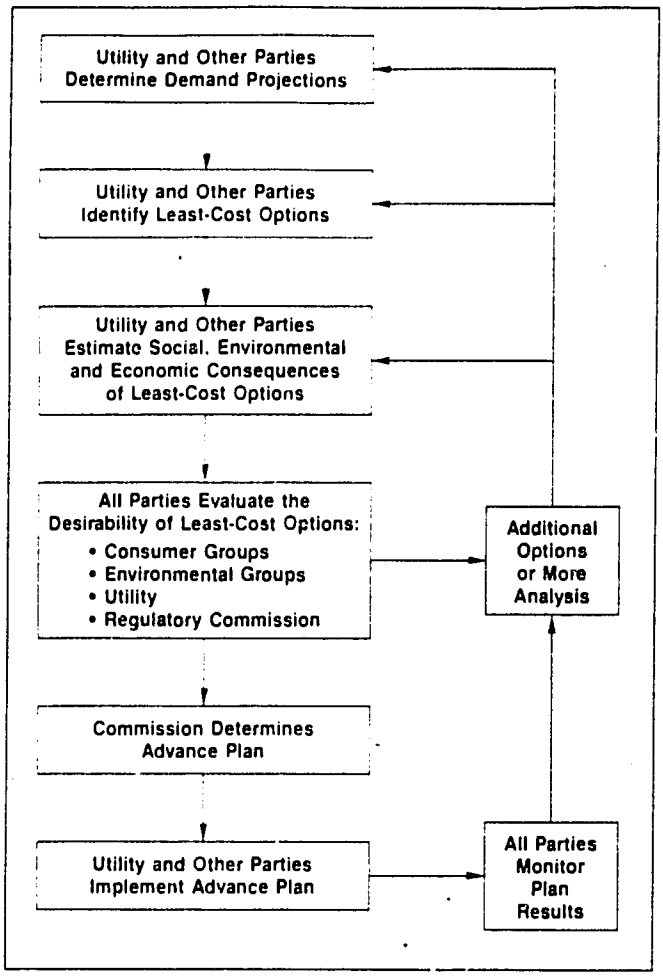


FIGURE 2: Electric utility least-cost planning.

Least-cost planning can be justified under conditions of market failure. Market failure can occur when there are technological barriers to full competition, environmental and social externalities, significant transaction costs, and information problems (Bator 1958; Breyer 1982; Schmalensee 1979). If the production technology exhibits significant economies of scale and scope, the competition process will limit the number of viable providers in the market. Surviving providers will exploit their market position (assuming myopic self-interest) at the expense of social welfare improvement. This is the traditional natural monopoly argument given in defense of public utility regulation, whether or not traditional or least-cost planning is used (Sharkey 1982). For electric utilities, there are extensive economies of scale in transmission. To a lesser degree, there have been scale economies in generation unit size for central station plants and in the size of generating utilities (Christensen and Greene 1976).

Market failure caused by technological barriers provides a justification for social control over the planning process through least-cost planning. A utility practicing traditional planning may use its construction program, with its associated technology choices, as an effective stratagem for capturing at least a portion of the "market exploitation potential" inherent in its market position.[7] In such instances, least-cost planning rather than traditional planning may be necessary to ensure that the profit control and efficiency objectives set by a regulatory commission are met.

The existence of "non-internalized externalities" such as environmental pollution can also lead to market failure. In the neoclassical view, resource utilization and technology choice decisions made in a market economy reflect the objectives and relative bargaining strengths of market participants. Either the impact of external market exchanges on those individuals or groups with little or no market voice are not considered by market participants, or the market participants have a difficult time trying to effectuate a market-based redress of environmental externalities.

Least-cost planning provides one means for addressing the market failures arising from environmental externalities. An integral element of least-cost planning is assessment of the environmental consequences of the various demand-side and supply-side options. With least-cost planning, environmental concerns can be treated more directly and flexibly than in traditional planning, where such concerns are handled simply as a constraint.

The substantial transaction costs in the purchase of demand-side options by utility customers can also serve as a rationale for least-cost planning. Transaction costs are incurred when customers decide to adopt demand-side options, such as equipment replacement or modification, building efficiency improvements, or altered ways of using energy. These transaction costs arise because of bounded rationality and opportunism (Schmalensee 1979). Bounded rationality refers to the difficulty customers have in finding and using product information in making purchase decisions. Opportunism arises when a buyer or seller can exploit the other party by virtue of transaction-specific characteristics of the product. For example, a vendor may recommend electronic ballasts and energy-saving fluorescent lamps to the manager of an existing commercial building. Because relamping is infrequent, the manager is unlikely to be well informed on the cost and performance of relatively new lighting products and on whether the proposed lighting is appropriate for the specific applications. To respond to the transaction cost problem, least-cost planning may be needed to identify alternative and appropriate levels of utility involvement in the provision of demand-side services.

Information problems are also a cause of market failure. Optimal market outcomes are unlikely without full information being available to customers, utility managers, and the regulator. While utilities may have a good information base about present and future supply options, customers generally are not extensively aware of demand modification alternatives, or of the future supply conditions (including future prices). The least-cost planning process fosters a better information base than traditional

-62

planning and provides justification for disseminating such information to all parties.

Institutional economists view the economy as a constantly changing and evolving process thrust upon the society by changes in technology, resource base, social standards, personal preferences, and so forth. The major economic problem, as viewed by institutionalists, is how to structure the forms of social and economic interaction to best accommodate change.

Process is the means by which adaptation to unending change can take place. Beneficial processes are those that allow recognition of and adaptation to change with minimal social disruption. Nonbeneficial processes are those that thwart the recognition of social and technological change, thereby delaying social adaptation and increasing the subsequent cost of adaptation. From the institutional economic perspective, least-cost planning can both promote and accommodate technological progress because it focuses on more than supply technologies, and provides a mechanism for societally beneficial risk management because it involves more participants. For the same reason, least-cost planning also provides a means for sharing the power inherent in the choice of technological paths.

The institutionalists are concerned with technological choice as a process because it directs society down discrete evolutionary pathways. Decision makers tend to favor those options that are familiar and that are congruent with their (or their organization's) self-interest. Thus, it would not be surprising if utility system planners using traditional planning favored familiar, supply-side options that draw on the established capabilities of the electric utility rather than on demand-side options that involve technologies with which they are less familiar. Least-cost planning moves the locus of decision making. By engaging in public planning and by requiring level playing-field treatment of supply-side and demand-side options, least-cost planning can lead to a more timely consideration and adoption of new alternatives for solving capacity shortage, environmental, and other problems.

Responses to Least-Cost Planning

Because of the major differences between traditional and least-cost planning, the parties to the process understandably have varying attitudes towards the changes occurring in electric utility planning. These attitudes vary in part with the relative gain or loss in decision-making power.

Several different organizations and interests advocate the application of least-cost planning to electric power planning. Some utilities see least-cost planning as reducing financial requirements and risks associated with the construction of large central station generating plants. By lowering demand growth, energy conservation and efficiency investments can reduce the capital requirements of the utility by obviating the need for new plant construction (Schneider 1986). For example, the Sawhill Report (Solar Energy Research Institute 1981) suggested that it is technically possible to reduce total energy and electricity use by 25 percent over the period 1977 to 2000, even if real GNP rises by 67 percent over the period. Amory Lovins (1985) argues that full use of the best electricity-saving measures now on the market could reduce ultimate U.S. electrical demand to approximately one-fourth its present level.

Regulators increasingly view least-cost planning as central to their regulatory responsibilities. Widespread plant cancellations, postponements, and cost overruns during the last decade have prompted regulatory commissions to take a closer and broader look at capacity expansion requirements. Cavanagh (1986) states that least-cost planning is fundamental to the state regulator's goal of maintaining reliable electricity service at the lowest possible cost. Also, new requirements, such as those prompted by the Public Utility Regulatory Policy Act (PURPA), have promoted demand-side and new supply-side options as alternatives to traditional electrical energy supply.[3]

Least-cost planning has also been embraced by several environmental organizations. In the 1970s, the environmental movement became increasingly critical of power plant construction and operation (Foell and Hanson 1980). Least-cost planning has drawn increasing support from environmentalists as a vehicle for the explicit consideration of environmental impacts of existing and proposed electric power plants and transmission systems.

Least-cost planning is not universally endorsed, however (*Electrical World* 1987; Benjamin 1986; Hayes and Scheer 1987). Some critics view least-cost planning as an inappropriate over-stepping of the boundary between regulatory review and utility management decision-making. Others see least-cost planning as simply a tool used by special interest groups (such as anti-nuclear groups and cogenerators) to achieve their own objectives. The movement towards reduced regulatory oversight of electric supply and the growing perception of a more competitive industry have been argued as reasons to turn away from the cooperative process of least-cost planning.[4] On the other hand, other observers argue that least-cost planning can actually increase competition in providing for energy needs.[5]

Multiattribute Decision Analysis and Least-Cost Planning

Despite the growth in the use of least-cost planning, there are barriers to full implementation. For example, there is a lack of coordination between regulatory commissions and separate siting agencies that may make it difficult to implement least-cost planning on a regional basis. In addition, commissions have insufficient resources to be thorough in their role in least-cost planning. And many utilities claim that the cost of least-cost planning procedures is excessive.

Many barriers hinder integrative evaluation of alternative options. Currently there is no agreement on the definition and scope of least-cost planning. Methodologies for integrating demand-side and supply-side options are

63

still being developed. In addition, many people are concerned about how risk analysis can be adequately incorporated in least-cost planning. The risks of demand-side options, for example, currently tend to be much more difficult to quantify, compared with supply-side risks. And there is considerable disagreement on adoption rates, saturation levels, cost, and load-shape effects of demand-side programs. Furthermore, various components of a least-cost planning evaluation—such as the value of power system reliability—may be difficult to quantify. Certain elements—environmental and social costs, for example—may be inherently unquantifiable. Goldman et al. (1989) summarize the research needed to overcome barriers to wide-scale use of least-cost planning.

Given the numerous interested parties, as well as the multifaceted effects of electric utility programs, a significant difficulty in applying least-cost planning to electric power planning is keeping the planning process tractable. Coping with this difficulty requires analytical techniques and decision-making frameworks for collecting and analyzing information, expressing values, mediating between parties, and ultimately, making decisions. Because multiattribute decision analysis provides an attractive decision-making framework, and because it has been applied to energy-related problems (see, for example, Buehring et al. 1976; Keeney et al. 1985; Keeney 1980; Manne and Richels 1978; Otway and Edwards 1977; Peerenboom et al. 1984; Peerenboom and Foell 1985; Wichert and Hanson 1987; Woodward-Clyde Consultants 1982), we investigated its use in least-cost planning.

Multiattribute decision analysis can facilitate decision making within a complex planning environment by enabling systematic evaluation of alternative programs. Multiattribute analysis explicitly recognizes and incorporates value judgments, and formally incorporates both quantitative and qualitative measures for evaluating outcomes—important advantages over more traditional policy evaluation methods, such as benefit-cost analysis. For a single decision maker, this evaluation proceeds by (1) identification of objectives (economic, environmental, social, etc.); (2) estimation of program outcomes for each option and for each objective; (3) explicit specification of the decision maker's preferences for each objective; and (4) ranking of the program options based on their attainment of the stated objectives. For multiple decision makers or interested parties (as in the planning process illustrated in Figure 2), a subsequent consensus or negotiating process may be followed to reach the final ranking.[6] As with any type of decision support technique, the overall process and rankings of options are aids to arriving at decisions in complex situations with multiple conflicting objectives. The technique will typically be used in an iterative fashion as users struggle with difficult trade-offs between objectives and overall planning options.

Multiattribute decision analysis is based on utility theory. The program objectives are reflected in quantifiable attributes that become arguments of the decision maker's utility function. Given the specification of a set of n objectives, a set of attributes $\{X = (X_1, X_2, \ldots, X_n)\}$ can be defined where attribute X_i is associated with the ith objective. Attribute levels for a specific option can be denoted as $\{x = (x_1, x_2, \ldots, x_n)\}$. Thus, the decision maker's utility for an option can be represented as $\{U = U(x)\}$. Given a suitable specification of the utility function, $U(X)$, and determination of the attribute levels of each option, the program options can be systematically ranked where some option m would be preferred to option n if $U(x_m) > U(x_n)$.

The additive and multiplicative utility function specifications are used extensively in multiattribute decision analysis (Keeney 1980; Keeney and Raiffa 1976). Both formulations assume that the utility function is separable in its arguments, so that, $U = f[U_1(x_1), U_2(x_2), \ldots, U_n(x_n)]$ where U_i is the utility derived from the x_ith attribute outcome for some option. Furthermore, $U_1, \ldots, U_n$ are assumed to be independent. Given a set of preference weights $\{k = (k_1, k_2, \ldots, k_n)\}$, where k_i is the preference weight for the X_ith attribute, the additive and multiplicative utility functions can be specified respectively:

$$U(x) = \sum_{i=1}^{n} k_i U_i(x_i), \quad \text{with} \quad \sum_{i=1}^{n} k_i = 1; \qquad [1]$$

and

$$1 + wU(x) = \prod_{i=1}^{n} (1 + wk_i U_i(x_i)) \qquad [2]$$

with w such that

$$1 + w = \prod_{i=1}^{n} (1 + wk_i) \quad \text{and} \quad \sum_{i=1}^{n} k_i \neq 1.$$

Within the context of state utility regulation where there are multiple participants in the decision-making process, there are two promising approaches for using multiattribute decision analysis to guide an electric utility least-cost planning process. In the first approach, each participant (such as a utility, an industrial consumer, a residential consumer organization, or an environmental organization) would use multiattribute decision analysis as a decision aid for proposing a set of options from the standpoint of their own explicitly stated objectives and preferences. The regulatory commission would then consider these proposals and views, and make a determination (as shown in Figure 2) of the most desired action.

In the second approach, the regulatory commission would specify the important objectives to be addressed by the various parties, including parties representing broad public interests, at the beginning of the decision-making process. Then, the participants would use the same set of objectives and associated attributes, but would use their own preferences and attitudes toward risk, and their own projections of consequences, to identify and rank options. This approach was implied in a recent order by the Wisconsin Public Service Commission

64

(1986) that required the electric utilities to explicitly consider the following issues in their advance plan filings:

- Health (e.g., respiratory diseases);
- Safety (e.g., accidents—deaths and injuries);
- Reliability (e.g., outages, certainty of conservation, or electric production);
- Environmental impacts—primary and secondary impacts (e.g., physical and biological wetland impacts, loss of habitat, acid deposition impacts, water quality impacts, endangered species impacts);
- Use of nonrenewable resources (e.g., coal, metals, petroleum);
- Social impacts (e.g., jobs, equity, loss of agricultural land/production);
- Economics (e.g., taxes, economic development, competition, price elasticity);
- Politics (e.g., legislation, public relations);
- Flexibility (e.g., risks, adaptability to external changes); and
- Technical innovation (e.g., new methods to serve load or achieve conservation).

Using Multiattribute Decision Analysis to Assess Trade-Offs

In our application of multiattribute decision analysis to least-cost planning, we pursued the first of the two approaches described above. Specifically, we worked with one participant, a major Wisconsin electric utility, while it prepared its filing as part of Wisconsin's advance plan process.[7] In the case study, we examined the questions "Could a decision support framework that explicitly considers values and addresses a wide set of commission issues be implemented at an electric utility?" and "Does the inclusion of the broader issues of least-cost planning (as represented in the commission issues) make a difference in the utility's preferred option?"

The electric utility was evaluating options for capacity expansion and conservation to determine which one would constitute the most desirable least-cost plan. We used multiattribute decision analysis to assess the following limited set of alternatives for the utility:

1. Retiring four units at an existing facility and implementing no demand-side programs, thus causing a new base load coal unit to be needed sooner;
2. Retrofitting four coal units (130 megawatts each) with atmospheric fluidized bed combustion (AFBC) and implementing 150 megawatts of conservation programs;
3. Retrofitting four coal units with AFBC and implementing 445 megawatts of conservation programs by 1990; and
4. Retrofitting two coal units with AFBC and implementing 445 megawatts of conservation programs.

Seven utility managers and outside experts were interviewed regarding their objectives, preference structures, and attitudes toward the riskiness of planning options. To determine preference structures, the interviews

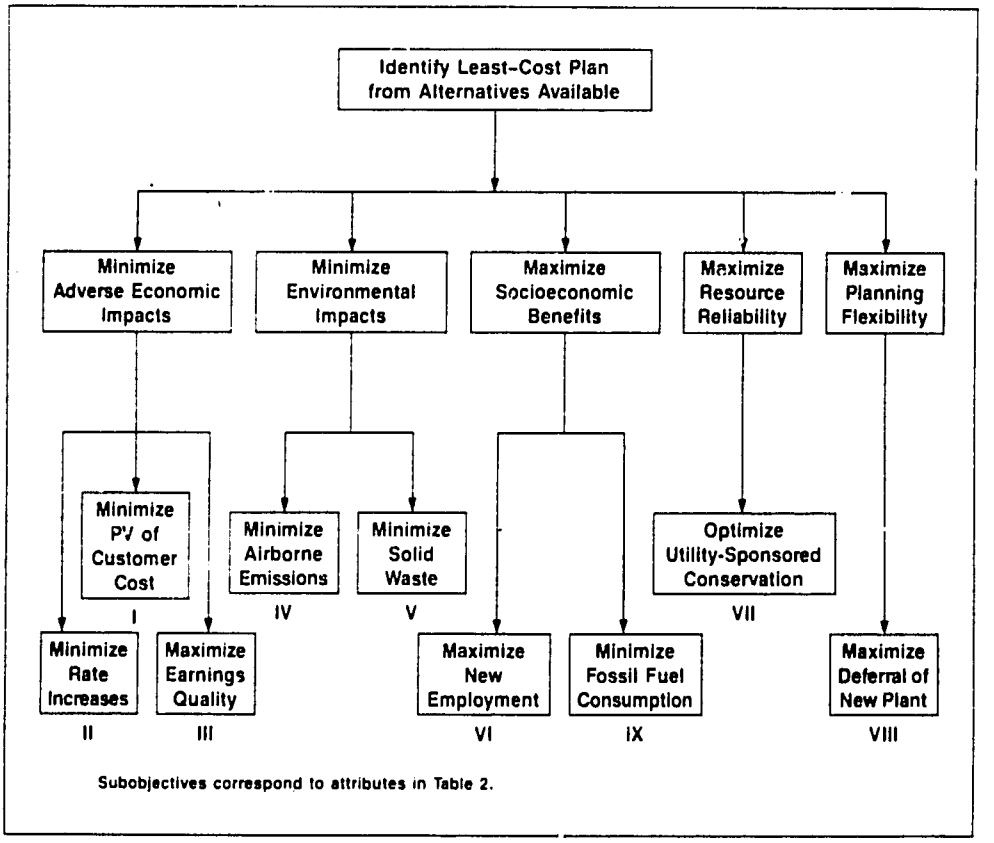


FIGURE 3: Objectives hierarchy.

65

TABLE 2: Summary of attribute values

Attribute	Alternative 1	2	3	4
I. PV customer cost ($ million 1986)	16.601	16.485	16.923	16.862
II. Levelized rates (cents/kwh 1986)	6.16	6.28	6.54	6.52
III. AFUDC/net income (avg. percent)	15.7	10.5	6.3	9.2
IV. SO_2 emissions (avg. tons/yr.)	76,876	74,432	70,458	71,884
V. Solid waste (10e3 tons/yr.)	1,924	1,288	1,168	908
VI. New employment (jobs created)	178	206	395	375
VII. Conservation (mw)	0	150	445	445
VIII. Baseload plant (in-service date)	1995	2006	2010	2008
IX. Coal consumed (10e6 tons)	174	162	154	151

followed the procedure described by Keeney (1980). The nine objectives identified by the managers and outside experts are listed in Figure 3. Attribute values for the four alternatives are given in Table 2. They are matched to and in the same order as the objectives shown in Figure 3.

Our study revealed considerable differences among the managers and outside experts about the reliance on "megawatts" of demand-side conservation as a replacement for new generating units. Among the seven managers and experts some believed that demand-side capacity is less reliable than supply-side capacity, so that the utility or value of demand-side capacity is inversely related to the quantity of demand-side capacity in a planning option. Other managers and experts felt, however, that some demand-side capacity was very valuable both for cost savings and for gaining direct experience with these measures. As a consequence, the value or utility rose with demand-side capacity. For other attributes, there was closer agreement on preferences. In general, the managers and experts felt that the desirability of a particular option increased as the present value of total costs decreased, cents per kwh decreased, SO_2 emitted decreased, and in-state jobs increased.

The managers and experts demonstrated considerable differences in their weighting of the attributes and in the shape of their utility functions for each attribute. The weights chosen by the managers and experts are summarized in Table 3. The median weights suggest that the managers and experts had a high interest in keeping customer prices and the cost of service from rising, and that they had a relatively lower concern for improving employment and reducing consumption of coal.

Despite the differences in preference structures, option 2, retrofitting four units and 150 megawatts of demand-side programs, was favored by four of the seven managers and experts. Two others favored option 4, which incorporated even more demand-side programs. Notably, some of the options that had not seemed very attractive to the utility managers and experts at the outset were eventually shown to be desirable, given their objectives and preference weightings. The most preferred alternatives for each manager and expert are shown in Table 3.

The objectives sought and options assessed in the advance plan process are crucial to the selection of the preferred option. If the only attributes considered are the traditional planning concerns of price and overall cost (attributes 1 and 2 in Tables 2 and 3) then, as shown in Table 4, the preferred alternative shifts for six out of the seven managers and experts. Clearly, the additional decision dimensions of least-cost planning had a significant impact on the decision process in this case.

An Organizing Framework

Least-cost planning, which is being adopted throughout the electric utility industry, underscores the growing importance for planners in electric utility planning (and in

TABLE 3: Attribute weights and preferred alternatives

Manager/expert	Weight (%) for each attribute 1	2	3	4	5	6	7	8	9	Preferred alternative
A	6.2	16.5	0.0	4.1	12.3	2.5	32.9	24.7	0.8	2
B	21.9	43.9	5.7	13.2	4.4	0.9	5.3	4.4	0.4	2
C	6.4	19.5	2.1	5.8	11.8	14.3	9.7	14.8	15.6	4
D	16.6	33.1	0.0	19.9	6.6	3.3	13.2	4.0	3.3	2
E	19.8	19.4	0.0	13.1	12.3	5.6	11.2	14.9	3.7	2
F	1.0	55.0	20.0	1.0	1.0	11.0	5.0	1.0	5.0	1
G	11.9	17.9	6.0	23.8	20.2	3.6	9.5	2.4	4.8	4
Minimum	1.0	16.5	0.0	1.0	1.0	0.9	5.0	1.0	0.4	
Median	11.9	19.5	5.7	13.1	11.8	3.6	9.7	4.4	3.7	
Maximum	21.9	55.0	20.0	23.8	20.2	14.3	32.9	24.7	15.6	

TABLE 4: Sensitivity of options to the additional decision criteria in least-cost planning

Manager/expert	Preferred option: Price and cost attributes only	Preferred option: All attributes
A	1	2
B	1	2
C	2	4
D	1	2
E	1	2
F	1	1
G	1	4

other planning arenas as well) to consider multiple options, multiple objectives, and explicit preferences. It also highlights the importance of viewing electric utility planning as a participatory process rather than just a mechanical use of analytical tools. While planners in other areas, such as land use, transportation, housing, and community development, may be comfortable with this conception of planning, it is a departure in electric utility planning. However, it is a departure with considerable support in economic thought.

The experience with least-cost planning in Wisconsin generally and in our case study suggests that least-cost planning is workable, and will result in outcomes different from those of the traditional planning process. This experience also suggests that the process can generate greater public involvement and a sharper focus on the public interest.

As a tool, multiattribute decision analysis can provide a unique contribution to least-cost planning by serving as an organizing framework for the planning process. Multiattribute decision analysis can be particularly valuable in identifying least-cost planning issues and objectives. It can also be a valuable decision aid for clarifying the basis of disputes among different interest groups regarding their objectives, preferences, and expectations as to the consequences of specific demand-side and supply-side options. Ranking options using multiattribute decision analysis can help identify how and why various stakeholders disagree over the relative desirability of various least-cost options.

While we view multiattribute decision analysis as an attractive framework for undertaking least-cost planning, undoubtedly it is not the only framework. Any chosen framework, however, must address the numerous dimensions of least-cost planning, and must explicitly consider the unavoidable role of values and judgment of participants in the electric utility planning process.

NOTES

1. Survey results attest to the widespread interest among state regulatory commissions. Examples of these surveys are reported in Hayes and Scheer (1987), Markowitz and Kriesbur (1985); Shapiro, Markowitz, and Hirsch (1987); Berry (1988); and Chamberlin, Fry, and Braithwait (1989).
2. Berg and Tschirhart (1988) discuss various technological choice strategems associated with different regulatory incentives (such as the Averch-Johnson effect) where utilities have the incentive to choose relatively more capital-intensive technologies under rate-of-return regulation.
3. For example, under PURPA, utilities are required to purchase electric power from cogenerators and small power producers, thus promoting new, nontraditional supplies of generating capability.
4. In recent years there has been a movement toward greater reliance on competing supply sources for electric power generation among electric utilities. For example, as noted previously, PURPA Section 210 fostered the growth of cogenerated power by enabling cogenerators to avoid traditional utility regulation and by requiring utilities to purchase power from these sources. Furthermore, various states, such as Maine and Massachusetts, have adopted competitive bidding provisions for new sources of electric power supply.
5. For a regulatory commissioner's point of view on the matter, see Munts (1988). In fact, the Public Service Commission of Wisconsin has encouraged competition in the supply of conservation measures (Wisconsin Public Service Commission 1988).
6. Lee and Wiggins (1988) reported on a multiattribute application that incorporated a formal mediation component.
7. A more detailed discussion of many aspects of our application is found in Kidwell (1988). A desirable extension of our case study would be to undertake parallel applications with various parties who would participate in an advance plan process. We could not make this extension because, at the time of the study, our utility's planning options were not public information.

REFERENCES

Bator, Francis M. 1958. The Anatomy of Market Failure. *Quarterly Journal of Economics* 72, 3: 351–79.

Benjamin, Stan. 1986. Least-cost for Whom? *Electric Perspectives* (Summer): 9–18.

Berg, S., and J. Tschirhart. 1988. *Natural Monopoly Regulation: Principles and Practice.* New York: Cambridge University Press.

Berry, D. 1988. Least-cost Planning and Utility Regulation. *Public Utilities Fortnightly*, March 17: 9–15.

Breyer, Stephen. 1982. *Regulation and Its Reform.* Cambridge, MA: Harvard University Press.

Buehring, W. A., W. K. Foell, and R. L. Keeney. 1976. *Energy/Environment Management: Application of Decision Analysis.* Report RR-76-14. Laxenburg, Austria: International Institute for Applied Systems Analysis.

Cavanagh, Ralph C. 1986. Least-cost Planning Impera-

tives for Electric Utilities and Their Regulators. *The Harvard Environmental Law Review* 10, 2.

Chamberlin, J., T. Fry, and C. Braithwait. 1989. Status of Least-Cost Planning in the United States-Summary. Report RP2982-02. Palo Alto, CA: Electric Power Research Institute.

Christensen, Laurits, and William Greene. 1976. Economies of Scale in U.S. Electric Power Generation. *Journal of Political Economy* 84, 4: 655–76.

Electrical World. 1987. Least-cost Planning: Much Ado about Nothing? (June): 17–18.

———. 1988. Annual Industry Forecast (October): 67–72.

Foell, W. K., and M. E. Hanson. 1980. Futurists and State Energy Policy: the Wisconsin Story. *Technological Forecasting and Social Change* 18: 341–58.

Gellings, C. W., J. H. Chamberlin, and J. M. Clinton. 1987. *Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least-cost Planning and Demand-Side Management*. Report EM 5065. Palo Alto, CA: Electric Power Research Institute.

Goldman, C., E. Hirst, and F. Krause, eds. 1989. *Least-Cost Planning in the Utility Sector: Progress and Challenges*. Lawrence Berkeley Laboratory, LBL-27/30. Oak Ridge National Laboratory, ORNL/CON-284. Oak Ridge, TN: Oak Ridge National Laboratory.

Hayes, Mary Sharpe, and Richard M. Scheer. 1987. Least-cost Planning: A National Perspective. *Public Utilities Fortnightly*, March 19: 13–18.

Keeney, R. 1980. *Siting Energy Facilities*. New York: Academic Press.

Keeney, R. L., and R. L. Winkler. 1985. Evaluating Decision Strategies for Equity of Public Risks. *Operations Research* 33, 5: 955–70.

Keeney, R. L., and H. Raiffa. 1976. *Decisions with Multiple Objectives*. New York: John Wiley.

Kidwell, Stephen. 1988. Multiattribute Decision Analysis: An Application to Least-cost Integrated Planning for Electric Utilities. Master's thesis, Institute for Environmental Studies, University of Wisconsin-Madison.

Lee, Yi-Chin, and Lyna Wiggins. 1989. MEDIATOR: An Expert System to Facilitate Environmental Dispute Resolution. In *Expert Systems: Applications to Urban Planning*, edited by T. John Kim. Springer-Verlag.

Lovins, Amory. 1976. Energy Strategy: The Road Not Taken. *Foreign Affairs* 55: 65–96.

———. 1985. Least-cost Electricity Strategies for Wisconsin: Practical Opportunities to Save over a Billion Dollars a Year. Direct Testimony before the Public Service Commission of Wisconsin in Docket 05-EP-4: 20-21. Madison, WI.

Manne, A. S., and R. G. Richels. 1978. A Decision Analysis of the U.S. Breeder Program. *Energy* 3: 747–67.

Markowitz, Paul, and Joseph Kriesbur. 1985. *Least-cost Planning: Is There Really a State Movement?* Washington, DC: Critical Mass Energy Project, Energy Conservation Coalition.

Munts, Mary Lou. 1988. Least-Cost Planning and Competition—A State Regulatee's Perspective. Wisconsin Public Service Commission, April 14.

Naill, Roger, and Roger Sant. 1984. Electricity Markets in the 1990s: Feast or Famine? *Public Utilities Fortnightly*, April 26: 19–23.

Otway, H. J., and W. Edwards. 1977. *Application of a Simple Multiattribute Rating Technique to Evaluation of Nuclear Waste Disposal Sites: A Demonstration*. Report RM-77-31. Laxenberg, Austria: Institute for Applied Systems Analysis.

Peerenboom, J. P., W. A. Buehring, and T. W. Joseph. 1984. *A Decision-Analytic Framework for Portfolio Selection: Choosing Among Supplemental Environmental Research Projects Proposed for the Great Plains Coal Gasification Facility*. Report ANL/AA-31. Argonne, IL: Argonne National Laboratory Report.

Peerenboom, James P., and Wesley K. Foell. 1985. A Decision Analysis Approach to Energy System Expansion Planning. *The Energy Journal* 6, 3: 21–36.

Sant, Roger. 1979. *The Least-cost Energy Strategy*. Arlington, VA: Energy Productivity Center, Mellon Institute.

Sant, R., D. Bakke, and R. Naill. 1984. *Creating Abundance: America's Least-cost Energy Strategy*. New York: McGraw-Hill.

Schmalensee, Richard. 1979. *The Control of Natural Monopolies*. Lexington, MA: Lexington Books.

Schneider, Claudine. 1986. Least-cost Utility Planning: Providing a Competitive Edge. *Public Utilities Fortnightly*, April 17: 15–21.

Shapiro, Lisa, Paul Markowitz, and Nancy Hirsch. 1987. *A Brighter Future: State Actions in Least-cost Electrical Planning*. Washington, DC: Energy Conservation Coalition.

Sharkey, William W. 1982. *The Theory of Natural Monopoly*. New York: Cambridge University Press.

Solar Energy Research Institute. 1981. *A New Prosperity, Building a Sustainable Energy Future*. Andover, MA: Brick House.

Wichert, Donald, and Mark Hanson. 1987. The Application of a Formal Decison Analysis Procedure to State Energy Oil Overcharge Program and Policy Development. *Proceedings of the Third International Conference on Energy Conservation Program Evaluation: Practical Methods, Useful Results*. Chicago, IL.

Wisconsin Public Service Commission. 1986. Findings of Fact, Conclusion of Law, and Order. In Docket 05-EP-4. Madison, WI.

———. 1988. Application of Madison Gas and Electric for Authority to Increase Electric and Natural Gas Rates. June 14.

Woodward-Clyde Consultants. 1982. *Decision Framework for Technology Choice*. Report EQ-2153. Palo Alto, CA: Electric Power Research Institute.

Full-Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation

Not just power system planning, but operations as well, should reflect the full cost of alternatives. This practice is now feasible and would reduce total costs of power supply, while increasing rates only slightly.

Stephen Bernow, Bruce Biewald, and Donald Marron

The generation of electricity from power plants imposes a variety of burdens on the environment (e.g., emissions of atmospheric pollutants) which, through a variety of pathways and interactions, can cause damage to human health, ecosystems, economic productivity, and cultures. While these impacts often occur far from the sources of pollution, both spatially and temporally, they are a genuine cost of electricity production and use.

Whether through the damages sustained, or efforts to remediate the damages, these costs are ultimately borne by society, even if that burden is not distributed equally across geography or generations. Moreover, environmental costs that are not currently internalized may become so later as policy and regulation are changed to reduce pollutant loadings.

Electricity planners have begun to recognize such environmental externalities in *long-range planning* and resource procurement decisions. To be consistent and economically efficient, however, it is appropriate that *short-run operating* decisions also incorporate these externalities. Despite the current momentum toward energy efficiency and the use of less-polluting resources, the major sources of utility pollution for the foreseeable future will continue to be existing power plants; this situation will change only gradually as newer, more efficient plants are brought into service. Thus, while least-cost energy/environmental

Steve Bernow *is a founding member of Tellus Institute, where he is co-director of the Risk Analysis Group. He has been involved in utility planning and research in a variety of projects in the U.S. and abroad. He received a B.S. from the school of applied science and engineering and a Ph.D. in physics from Columbia University.*

Bruce Biewald *is a senior scientist and manager of resource planning projects within the Energy Systems Research Group at Tellus. He has analyzed technical aspects of utility systems and testified before several state regulatory commissions. He is developing a linear programming model for exploring strategies for acid gas emission in Europe.*

Donald Marron *is a research associate at Tellus, where he has evaluated electricity supply and resource options. He received a B.A. in mathematics from harvard University and is a graduate student in economics at Massachusetts Institute of Technology.*

planning will help secure a more socially rational *future* energy system, *current* energy production will continue to impose unnecessary environmental burdens on society.

To avoid this consequence, the dispatching of electric utility system resources should attempt to minimize the total societal costs of power generation. While this approach would alter traditional economic dispatching practices, it is a natural extension of recognition currently being given to environmental and other externalities in electric utility planning.

The difference is largely one of time-frame. System planners make resource commitments for periods of many years, while system operators work in fractions of hours. In both cases, however, the objective should be the same: to provide electricity at the lowest possible cost, where cost to society includes both direct and indirect costs of electricity production. If planners and operators seek to achieve different objectives, they will undermine each other's efforts and optimum use of society's energy resources will not be achieved.

I. Electric Generating Resource Externalities

Economists refer to the cost implications of a decision that are not borne by the decision-maker as externalities.[1] A typical externality is the cost of pollution, or, more accurately, its cost impact in terms of damage to structures, ecosystems, productivity, and human health.

Among the most widely recognized externalities resulting from electricity generation are the emissions of air pollutants from power plants. Power plants also pollute and heat bodies of water and create substantial volumes of solid waste. Nuclear plants create radioactive wastes: high-level waste consisting of irradiated fuel rods and assemblies and low-level waste consisting of contaminated equipment and supplies; they also routinely release radioactive air emissions, as do some fossil-fueled plants.

Regulation can internalize externalities by ensuring that they are included in the decision calculus and by requiring those responsible for the costs to bear them.

The operation of power plants can also have other direct external costs. For example, operation of hydroelectric plants can kill vast quantities of fish or alter river habitats.[2] These resources have substantial commercial and recreational values to society, so damage can be very costly.

While emissions of air toxics and fish kills are important *direct* externalities of electric generation, important externalities may also be *indirect*, as in the case of oil spills. In general, oil spills occur far from a power plant site and do not directly result from electric generation. They do, however, result indirectly from the consumption of oil for electric generation: the use of oil increases the need to transport oil, in turn increasing the probability of oil spills and their associated damages to the environment. This increase in spill probability is an indirect externality of oil-fired power plants. Similar indirect impacts of electricity generation and use occur throughout the electric fuel cycle, from extraction, processing, and transport of fuels to plant construction to energy conversion at the plant to decommissioning and waste disposal.

While each of these stages of the fuel cycle is involved in planning decisions, only some are affected by operating protocols. While planning protocols for including externalities will, in principle, need to consider all these stages, operating protocols can be more focused. For the purposes of incorporating externalities in operating decisions, it is likely that it will be sufficient to concentrate on those impacts that, like fuel costs, increase or decrease with plant output.

II. Internalizing Environmental Costs

Regulation can internalize externalities by ensuring that they are included in the decision calculus and by requiring those responsible for the costs to bear them. The traditional approach is through

environmental regulations that establish restrictions with which utilities must comply, leaving utilities and utility regulators to focus on costs already deemed internal.[3]

Significant external costs remain, however, either because the environmental restrictions do not set pollution limits at zero, or because they do not address certain pollutants, such as CO_2, at all. Moreover, as environmental restrictions are developed they generally apply only to new sources.[4]

Those externalities that remain are receiving increasing attention by utility planners and regulators. In utility planning studies, the environmental impacts of various resource plans are often cited as important in deciding among plans.[5] Utilities will sometimes choose resource plans with higher direct costs, if they are less environmentally damaging.

Regulators have begun to address the issue of externalities in resource planning and acquisition in many states and by a variety of means. In some states such as Wisconsin, non-polluting resources are given a specific cost advantage over polluting resources. In states like New York, Massachusetts and California, regulators have determined that the environmental costs of air emissions, expressed in dollars, should be included in overall resource planning just as the costs of fuel and plant construction are. In this way, the costs of air emissions are internalized to the resource selection process. Other states, e.g., Vermont and Nevada, are considering similar approaches.[6]

In each of these states, the focus has been on new resources and not on the volumes of pollution produced by use of existing facilities. Thus, despite their increasing recognition by planners, environmental externalities are not reflected in the decision protocols of utility system operators.

An important exception to this emphasis upon new resources is the emissions cap established in

the new Clean Air Act amendments. By allowing emissions trading as a means of complying with an overall U.S. limit on SO_2 emissions, the Act brings existing generating resources into the group of options to be considered in a compliance plan. By reducing emissions at existing resources, allowances may be freed for use at other resources or for sale to another utility. Full-cost dispatch (or more precisely, dispatch including the market price for SO_2 allowances) is one of many approaches that may be used to reduce emissions from the system. In fact, with the passage of the Clean Air Act amendments, the market price for emissions allowances should now be factored into the dispatch protocols of every U.S. electric utility, effectively requiring that some form of environmental dispatch be adopted.

III. Conventional Economic Dispatch

Electric utility system operators use economic dispatching principles to make optimum use of existing generation or purchased power resources to serve customer loads. Typically, a computer system loaded with information about the costs and operating efficiencies of these resources determines the mix to be dispatched on an hourly or shorter basis. Typically, resources are operated to serve customer loads in priority order based upon their incremental operating costs.

Conventional economic dispatch proceeds from lowest to highest cost resources to ensure overall economies in the production of electricity. Generating units with low variable operating costs, such as hydro, nuclear, and some low cost coal-fired units are dispatched first and will be operated even during low load periods.[7] Most coal-fired plants have higher variable costs and typically are next in the economic dispatch order. They may provide base-load service, or cycle to some extent to follow variations in customer load.

Finally, oil and natural gas-fired plants have higher variable costs,

and so often operate as peaking units, providing generation to serve customer loads only during high load periods.[8] New combined-cycle units burning natural gas have also recently become attractive options for baseload and cycling service because of their higher fuel efficiency (low heat rate) and lower variable costs.

From the standpoint of annual generation-related emissions, baseload and cycling units are of greatest importance, while peakers can become significant over shorter time periods.

In practice, all of the electric generating units on a system will be ranked by dispatchers according to their direct incremental costs. Within each class of units (coal, oil, etc.) there will be a range of incremental costs represented.

Sometimes, owing to differences in plant efficiency, there can be some overlap of plant types in the dispatch order. For example, an efficient oil-fired unit may have a lower incremental cost per unit of electricity production than an inefficient coal-fired plant, even though oil costs more per unit of energy input.

The efficiency of a generating unit typically varies with the output of the unit. The heat rate curves, which express this relationship between operating efficiency and the electrical output of the unit, are generally U-shaped. For this reason, the optimal use of system resources to serve a particular level of demand may have a number of units operating at partial capacity. The dispatch order will, in general, reflect different plants at different levels of output, rather than a simple sequence of plants. Figure 1 is a simplified representation of conventional economic dispatch. Customer electricity requirements are represented as a load duration curve or cumulative probability distribution.

IV. Dispatch Order: Direct Cost, Least-Emissions, or Total Cost?

A. Direct Cost Dispatch

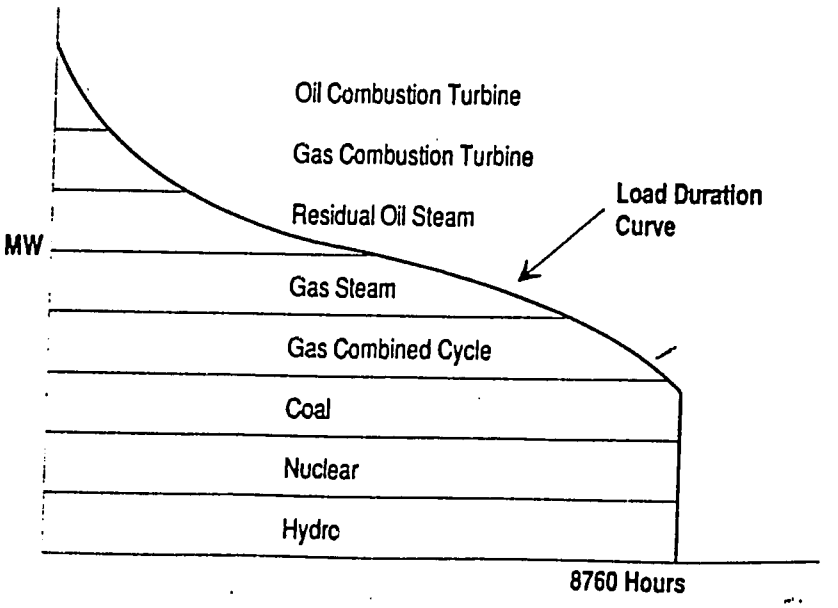
The procedure described above, in which electric resources are operated on the basis of direct fuel and variable O&M costs, may be termed direct-cost dispatch, partial-cost economic dispatch, or utility-cost dispatch. It aims for optimal use of resources only from the perspective of the electric utility system and its revenue requirements. A broader outlook would include the costs of plant operation beyond these direct costs. As discussed above, these additional incremental costs to society include the impacts of pollutants from the plant, both on the utility customers who benefit directly from the electricity produced and on other people and natural environments that do not so benefit.

Conventional economic dispatch can be expanded to incorporate these external costs.

B. Least-Emissions Dispatch

The term least-emissions dispatch has been used in various contexts and with various meanings. Strictly speaking, a least-emissions dispatching strategy would load the available resources in a priority order based *solely* upon emissions from the lowest emitter (or aggregate emissions cost) to the highest with no regard to fuel and O&M cost. Such an approach could produce dramatically different economic results, as compared with conventional dispatch. Whether such an outcome would be acceptable is a

FIGURE 1: Simplified Diagram of Economic Dispatch



social and economic policy question.

Recognizing an important category of external costs of electric plant operation (air pollution) the least-emissions concept goes part way toward full-cost dispatching, but stops well short, as it fails to recognize any of the other external costs of electricity generation. Moreover, the phrase least-emissions is ambiguous with regard to the treatment of multiple pollutants and the relative weights to give them. It could refer to a single pollutant among many, or it could refer to a simple aggregate of pollutant emissions. If society views the impacts of each pollutant differently, the aggregate incremental emissions from a resource could be a weighted sum of pollutants emitted, or sum of the societal costs of the pollutants.

Dispatching based on these costs would be a least-emissions cost dispatch, a variant of the least-emissions theme. These results would be similar to those of full-cost dispatch if the societal costs of emissions are much larger than the direct costs of electric generation.[9]

C. Full-Cost Dispatch

If aggregate environmental costs are added to the direct variable costs of generation in the system dispatch protocols, full-cost dispatch results. The multiple environmental attributes and direct costs of electric generation would be fully reflected in system dispatch.

Full-cost dispatch could be effected by ascribing values to environmental *loadings* (e.g., emissions). It could also be pursued in more site-specific detail by representing loadings, the transport of pollutants, the exposure of sensitive populations and systems, the dose-response relationships, and, finally, the value of damages caused. This could be done either in great detail or approximately by developing factors and algorithms that would effectively capture these relationships at a reasonable level of accuracy for the facilities on the system.

In short, valuation of the operating externalities of power plants can be pursued in a variety of ways. The approaches taken, the methods used, and the values assigned have been the subject of vigorous discussion of late, and differences may persist as analysis and discourse proceeds.

Another approach to the inclusion of externalities in power system operation would be to minimize incremental utility costs, subject to a set of emissions constraints.[10] Emissions-constrained dispatch is an alternative method for reflecting society's environmental concerns. These two methods need not, however, be viewed as fundamentally incompatible.

Since the societal cost of emissions is a complex matter of science, economics, policy, and values, setting the costs of environmental impacts for full-cost dispatch is not a precise exercise. At different monetary values for external costs, different levels of system-wide pollutant emissions would be achieved by full-cost dispatch. Similarly, setting different target levels of pollutant loadings will require different levels of direct costs. The marginal costs of reaching those target levels are thus the implicit values of the perceived marginal damages avoided. These two approaches "setting targets" and "ascribing monetary values" are functionally equivalent.

VII. An Example of Full-Cost Dispatch

To explore the potential implications of full-cost dispatch and compare it with both conventional economic dispatch and strict least-emissions dispatch, we will examine a simplified hypothetical system. This example will also provide some indication of the costs and impacts that may be associated with various dispatching methods for a large, diverse system. We will outline the characteristics of the hypothetical system, and then consider the results for this system under three methods of dispatching: (1) conventional economic dispatch, (2) least-

emissions dispatch, and (3) full-cost economic dispatch.

Our hypothetical system is modelled after the fossil fuel portions of the New York Power Pool (NYPP) and New England Power Pool (NEPOOL) systems. Table 1 shows the dispatch order for this system, with capacity ratings, energy generation (under conventional economic dispatch), heat rates, fuel costs, and variable O&M costs. The capacity contributions for each fuel type were selected to resemble the mix of fuel types in the Northeast U.S., while within each fuel type the hypothetical plant capacities are arbitrary. We have added some combined-cycle gas capacity to represent likely near-term capacity additions. Also, we have assumed that dual-fuel (oil/gas) facilities will burn gas only.

The amounts of energy generation were determined by fitting the resources under a simplified load duration curve derived from a probability density function for a normal distribution. The costs and heat rates were based on selected NYPP fossil fuel plants. These data were obtained from dispatch model runs developed for the New York State Energy Plan.[11] The variable production costs in the right-hand column are the sum of the fuel and variable O&M costs.

The dispatch simulation method used in our analysis is highly idealized. It uses average heat rates (rather than heat rate curves) and assumes that the outage rates for these fossil units are identical. These simplifying assumptions permit changes in dispatch to be determined in a straightforward manner, by flipping the order of generators under the load curve. While not entirely accurate, this simplified approach is adequate for illustrative purposes. It can be implemented in a spreadsheet model, thus avoiding the use of a complex probabilistic production-costing model, which would be needed to obtain more accurate results.

The simplified approach permits quick comparisons of dispatch methods to be made to a level of accuracy acceptable for illustrative purposes. Detailed studies of emissions dispatching should be done for specific actual systems to determine how much emissions could be reduced and at what cost. One such study, which explored SO_2 dispatch strategies for the state of Ohio,[12] employed a probabilistic production-costing model to explore SO_2 reducing dispatch strategies. The study found that "emissions dispatching appears to be a [*sic*] inexpensive way to quickly achieve substantial emissions reductions, no matter what other strategies it is used in combination with." Each electric system could conduct similar studies of their alternative dispatch strategies.

Emissions coefficients for the plants in the hypothetical system shown in Table 2 were based upon the NYPP fossil units used for the hypothetical system cost and efficiency assumptions.

A. Conventional Economic Dispatch

The first column of numbers in Table 3 shows the summary results for this system dispatched based upon variable production costs only. The total production

TABLE 1: Test System for Emissions Dispatch Analysis

	Capacity	Generation under conventional economic dispatch (GWh)	Capacity factor under conventional dispatch	Fuel cost ($/MMBTU)	Variable O&M cost (¢/KWh)	Variable heat rate (BTU/KWh)	Prod. cost (¢/KWh)
Coal with GGD	2000	14,016	80.0%	1.60	0.50	9,500	2.02
Coal, 2.37% sulfur	2000	14,016	80.0%	1.80	0.30	9,900	2.08
Coal, 1.83% sulfur	2000	14,016	80.0%	1.50	0.45	12,100	2.27
Coal, 0.82% sulfur	2000	11,339	64.7%	1.80	0.40	13,000	2.74
Oil steam, 1.5% sulfur	2000	9,763	55.7%	2.75	0.30	9,900	3.02
Oil steam, 1.3% sulfur	2000	12,654	72.2%	2.70	0.20	9,400	2.74
Oil steam, 1.0% sulfur	2000	2,540	14.5%	2.80	0.25	10,200	3.11
Oil steam, 0.75% sulfur	2000	1,721	9.8%	3.05	0.25	10,200	3.36
Oil steam, 0.70% sulfur	2000	1,121	6.4%	2.95	0.35	10,300	3.39
Oil steam, 0.30% sulfur	4000	1,123	3.2%	3.15	0.65	12,900	4.71
Gas steam	8000	23,004	32.8%	2.75	0.20	10,400	3.06
Oil CT	3000	177	0.7%	4.25	0.65	15,000	7.03
Gas, CT	2000	244	1.4%	3.05	0.30	15,000	4.88
Gas, CC	5000	34,558	78.9%	2.55	0.45	8,200	2.54
Total	40,000	140,292					

cost (fuel plus variable O&M) is $3 79 million, and total emis- are 790,075 tons of SO_2, 2 ,788 tons of NO_x, 119,881,000 tons of CO_2, and smaller amounts of other air pollutants.

We can estimate the societal cost of the air pollution from this dispatch using emissions values (cost per pound) for each pollutant. We have developed values for these pollutants using an approach based upon marginal control costs and regulators' revealed preferences.[13] The values resulting from that analysis are listed in Table 4. The Massachusetts Department of Public Utilities recently adopted these costs for use in Massachusetts.[14]

iplying the values in Table e amounts of pollution in Tab e 2 yields a societal cost of emissions of $6,133 million. The total societal cost is, therefore, $9,812 million ($3,679 million in direct costs plus $6,133 million in emissions costs).

B. Least-Emissions Dispatch

We can now examine a case in which the same system is dispatched according to the strict least-emissions method. Instead of using direct variable production costs (column 1 in Table 5) to determine the loading order, the emissions values (column 2 in Table 5) are used. The emissions value for a plant is determined by multiplying its emissions coefficients (lbs/kWh) by the set of emissions values ($/lb).[15]

Results for the strict least-emissions dispatch of the hypothetical system are provided in the second column of Table 3. Production costs have increased by $681 million relative to conventional dispatch, but the amounts of air emissions have, in general, gone down substantially. For example, SO_2, NO_x, and CO_2 have decreased by 74%, 28%, and 20%, respectively (though emissions of three of the less important pollutants have increased). The net result is a large reduction in emissions costs: from $6,133 million for conventional dispatch to $3,949 million for least-emissions dispatch. In this case, the least-emissions approach has lowered total societal cost as well.

The conventional economic dispatch entirely ignores environmental costs, while the strict least-emissions dispatch entirely ignores direct economic costs of fuel and O&M.

Could the system be dispatched such that overall costs to society are minimized? We believe that a full-cost economic approach to dispatching — based upon both direct and environmental cost — is both feasible and desirable.

C. Full-Cost Dispatch

For our hypothetical system, full-cost dispatching uses the combined costs per kWh shown in the right-hand column of Table 5. The results in Table 3 show a slightly higher overall pollution cost than for the least-emissions case (by 4%) and somewhat higher fossil plant production costs than for the conventional dispatch case (by 9%).[16] Overall, however, full-cost dispatch provides the best alternative, in that it results in the lowest total societal cost. Compared with the conventional economic dispatch case, full-cost dispatch saves $2.0 billion, about 33% of the emissions costs for the hypothetical system, at an additional direct cost of $344

TABLE 2: Emission Coefficients for Test System (lbs/MMBTu in)

	SO_2	NO_x	CO_2	CH_4	CO	Particulates	VOC	Emissions "Value" (1990¢/KWh)
Coal with GGD	0.3600	0.5300	220	0.0012	0.024	0.0300	0.0028	4.4601
Coal, 2.37% sulfur	3.3200	0.4000	220	0.0012	0.024	0.2400	0.0028	7.0002
Coal, 1.83% sulfur	2.9300	0.8490	220	0.0012	0.024	0.2200	0.0028	9.9737
Coal, 0.82% sulfur	1.3100	0.1500	220	0.0012	0.024	0.2600	0.0028	7.0410
Residual steam, 1.5% sulfur	1.6200	0.6250	169	0.0019	0.033	0.1000	0.0051	5.5752
Residual steam, 1.3% sulfur	1.4200	0.2810	169	0.0019	0.033	0.0530	0.0051	3.9441
Residual steam, 1.0% sulfur	1.0800	0.2810	169	0.0019	0.033	0.1000	0.0051	4.0906
Residual steam, 0.75% sulfur	0.8000	0.1900	169	0.0019	0.033	0.1000	0.0051	3.5274
Residual steam, 0.70% sulfur	0.7600	0.2810	169	0.0019	0.033	0.1000	0.0051	3.8619
Residual steam, 0.30% sulfur	0.3200	0.3000	169	0.0019	0.033	0.0919	0.0051	4.4247
Ga[illegible]n	0.0000	0.2670	117	0.0003	0.039	0.0029	0.0014	2.3789
Oil, CT	0.2120	0.5110	164	0.0016	0.116	0.0376	0.0359	10.3307
Gas, CT	0.0006	0.3950	118	0.0123	0.110	0.0134	0.0120	5.9907
Gas, CC	0.0000	0.2000	117	0.0003	0.033	0.0014	0.0013	1.6815

TABLE 3: Costs and Emissions for Various Dispatching Methods

	Conventional Economic Dispatch	Least Emissions Dispatch	Full Cost Dispatch
sts (millions of 1990$)			
Production costs	3,679	4,360	4,023
Emission costs	6,133	3,949	4,107
Societal costs	9,812	8,309	8,130
Emissions (tons/year)			
SO_2	790,075	207,373	257,777
NO_x	263,788	187,998	194,026
CO_2	119,881,000	95,734,000	97,442,000
CH_4	727	1,031	653
CO	21,468	28,275	24,359
Particulates	68,489	23,207	24,258
VOC	1,979	2,457	1,829

million, about 9% of the fossil fuel production costs of the system. The benefit-to-cost ratio is thus about 5.9 to 1.

At the same time, the overall societal (direct plus emissions) costs decrease by about 17%, from 9,812 million to $8,130 million. Averaged over the seven pollutants, pollution reduction by full-cost dispatch is effected at extra direct costs at about 17% of the value of the pollutant (e.g., the average SO_2 reduction cost of $272/ton compared with the reduction value of $1,600/ton, while for NO_x the average reduction cost was $1,156/ton versus the value of $6,800/ton).

This result is not a surprise. Indeed, by design the dispatch which is based upon the objective of minimizing societal costs will result in lower societal cost than dispatches based upon other objectives such as minimizing production costs or emissions. It can also be expected, in general, that the cost of pollution reduction will be lower than the value of the pollution reduced, the degree reflecting the particular conditions of the system.

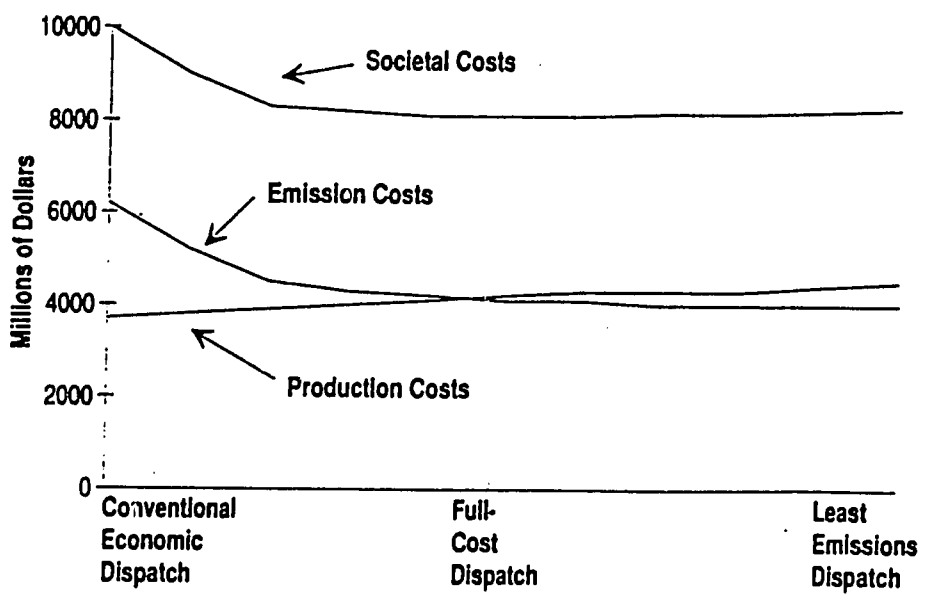
The results for the three dispatch methods, summarized in Table 3, show surprisingly little difference between the least-emissions dispatch and the full-cost dispatch approaches. This is depicted in Figure 2, where hybrid dispatch approaches fill out a curve between the three approaches discussed above. As the relative weight given to environmental costs is increased (moving along the x-axis), the direct production costs increase while the emissions costs decrease. The societal cost (production cost plus emissions cost) decreases to an minimum at full-cost dispatch, and then increases slowly.

For our hypothetical system, the shape of the societal cost curve shown in Figure 2 indicates that most of the savings are to be realized in the first small steps toward full-cost dispatch. Thus, in our example, setting the externalities values at only 40% of the full values used here, more than 80% of the emissions cost reductions obtained at full-cost dispatch

TABLE 4: Values Used for Air Emissions

	1990$/lb
SO_2	0.800
NO_x	3.400
CO_2	0.012
CH_4	0.115
CO	0.455
Particulates	2.100
VOC	2.750

FIGURE 2: Relationship Between Costs and Dispatch Method for Test System



would be effected, at a benefit-to-cost ratio of almost 10 to 1. The example also indicates that to go beyond full-cost dispatch toward least-emissions is neither costly nor efficacious, since both the production and emissions cost curves are rather shallow. It is not clear, however, that this would be the outcome for any particular real utility system.

VIII. Technical Constraints on Full-Cost Dispatch

The example above is idealized in several respects. It uses a hypothetical system, a simplified treatment of outage rates and heat rates, and it ignores real-time system operating constraints such as ramp rates, minimum loading levels, and minimum down time.

We have no reason to believe that the hypothetical system, or the simplification of outage rates and heat rates results in a bias one way or another in the results provided above. On the other hand, real-time considerations could place important constraints on emissions dispatch in practice, so actual emissions reductions will likely be somewhat lower than those forecast here. For example, the extent to which generation from coal units can be cut will certainly be limited by the minimum loading levels for those units.

This point was made, somewhat hyperbolically, by a New England utility official:

> It's practically impossible to do 'environmental dispatch.' From an engineering point of view, it just won't work. It would be utter chaos. The system will break down in about 15 minutes and you won't have any more NEPOOL. If you try to turn off a baseload coal plant in the afternoon and expect to turn it on again the next morning, it won't happen. Same goes for gas-fired peaking plants. If you run those for very long they will break down. Environmental dispatch is physically impossible.[17]

Although cast in near absolute form, these statements contain an important point of a relative nature: that there are physical constraints on the operation of generating units. Such constraints should be recognized in dispatching the system. This does not mean that no environmental dispatch can be performed, but that it will be subject to constraints and will thus realize lower levels of emissions cost reductions. For example, with full-cost dispatch, some especially dirty coal plants may run at very low capacity factors.[18]

It is important to remember that such constraints are not unique to environmental dispatch. Electric systems all over the world are currently dispatched by computer systems programmed to satisfy ramp rates and minimum loading constraints. The addition of environmental variable costs to direct variable costs would not fundamentally alter these considerations. Rather, it would (or could) cause a different set of units in a particular system to run up against the constraints.

It is common and sometimes necessary to make modifications to the system which impact the way in which generating units operate. Coal units were often built to back down expensive oil or gas generation. The many nuclear plant additions over the last decade were intended to back down more expensive fossil-fueled generation to achieve economies in direct variable costs. For example, with the addition of the three Palo Verde nuclear units to its system,

TABLE 5: Variable Costs of Operating Test System Fossil Plants

	Variable Production Costs (¢/kWh)	Emissions "Value" (¢/kWh)	Full Societal Costs (¢/kWh)
Coal with FGD	2.02	4.47	6.49
Coal, 2.37% sulfur	2.08	7.00	9.08
Coal, 1.83% sulfur	2.27	9.97	12.24
Coal, 0.82% sulfur	2.74	6.05	8.79
Residual steam, 1.5% sulfur	3.02	5.55	8.57
Residual steam, 1.3% sulfur	2.74	3.92	6.66
Residual steam, 1.0% sulfur	3.11	4.08	7.19
Residual steam, 0.75% sulfur	3.36	3.54	6.90
Residual steam, 0.70% sulfur	3.39	3.86	7.25
Residual steam, 0.30% sulfur	4.71	4.44	9.15
[illegible]am	3.06	2.37	5.43
Oil CT	7.03	6.04	13.06
Gas, CT	4.88	4.22	9.09
Gas, CC	2.54	1.68	4.22

the Arizona Public Service Company fossil-fueled unit capacity factors were expected to drop from an average of about 72% to about 54%, far below full availability, with some individual units lower still.[19]

Long-run performance of generating units can also depend upon the manner in which they are operated. Coal units are generally expected to operate at high capacity factors, with a minimum of load following, while combustion turbines are expected to operate at low capacity factors, often in a load following mode. However, it is far from clear that combustion turbines would perform poorly if operated in a baseload mode if that were needed to satisfy full-cost dispatch protocols. Combined-cycle plants, which frequently are used in baseload applications, use combustion turbines to generate electricity and feed the exhaust gas into a heat recovery steam generator. The combustion turbine portion of a combined-cycle facility often will be called upon for baseload operation. Modern combustion turbines can and do operate at capacity factors of more than 90%.[20] In a baseload mode of operation, performance could be further improved, as frequent startups can cause wear on the plant components.[21]

With regard to the use of coal facilities for cycling or peaking operation, there will be limitations. Subcritical coal units are designed to be cycled. That is, they can be brought down to minimum load (about 25% of total capacity) during nighttime periods and shut down on weekends. Supercritical units may be more constrained to baseload operation, but in a full-cost dispatch protocol might be taken off line entirely during low-load months in the spring or fall. The Arizona Public Service example above shows that such operation changes are made by utilities. The best approach to use in backing down coal plants will depend upon the particular generating

unit and the characteristics of its system.

Finally, it should be noted that many of the existing power plants that might be affected by full-cost dispatch are oil and gas steam facilities, which were originally built for baseload operation but operated late in the loading order in recent years owing to their higher fuel costs. If full-cost dispatch were to require increased operation of these units, this would be consistent with their original design.

Full-cost dispatch and the constraints under which it could operate can be readily represented in conventional production-costing and planning models that simulate system operation and the economics of alternative system plans.

IX. Operations and Planning Considerations

In conventional utility decisions the consistent protocols and assumptions are applied to planning and operations in order that least-cost results are realized. As noted earlier, the objectives of least *societal* cost require analogous consistency. The same external costs should, in principle, be ascribed for both planning and system operation.

For example, with the recognition of externalities, it might become desirable to retire particularly dirty baseload plants that might otherwise run infrequently, and to build new and cleaner plants. It might also become preferable to switch to cleaner fuels at existing plants, retrofit pollution control devices, or implement greater levels of conservation. Thus, investment decisions, fuel procurement decisions and operating protocols will affect one another. Interestingly, this would lead to a diminution over time of the gap between conventional and full-cost dispatch, as the system moves toward a cleaner mix of resources. This potential future outcome will not, however, obviate the need for full-cost dispatch, since there will remain some potential for further decreasing overall societal costs.

A balanced approach to reducing the environmental impacts of electric power supply would consider all reasonable opportunities, short-run and long-

run. After all, there is a continuum between dispatching decisions which are made hourly (or at even shorter intervals) and long-run planning commitments, which can span decades. If externalities are to be considered for planning but not operations, an arbitrary division could result. For example, it would be difficult to justify the consideration of externalities in a decision regarding a three-year energy conservation program while ignoring externalities in a decision regarding a short-term power purchase.

X. Full-Cost Dispatch and Electric Rates

The impact of full-cost dispatch on revenue requirements, rates, and customer electricity bills could be substantial in some systems, especially where low cost, high emissions generation resources dominate the overall mix of electricity production. For example, in a system for which coal provides most of the energy and gas or oil the peaking capability, switching from coal at 1.5 to 2.0 ¢/kWh to higher cost fuels at 3.5 ¢/kWh could almost double system energy costs. Overall revenue requirements, which include fixed costs, could increase greatly in such a case.

Of course, this is an extreme example. One-for-one switching between high and low cost fuels would be unlikely in most systems. Also, significant emissions benefits could be secured in some instances by switching between fuels closer in cost. Finally, system and unit operating conditions and constraints would restrict dispatch flexibility and, thus, the degree of fuel switching possible.

The actual impact will, therefore, be much less than the 50% in this extreme example. Indeed, for the hypothetical system evaluated earlier the impact on production costs alone was found to be less than 9% (implying less than 3% for the increase in total electricity prices, with fuel costs comprising roughly one-third of total revenue requirements).

The impact of full-cost dispatch on revenue requirements, rates, and customer electricity bills could be substantial in some systems.

For those systems that are expected to incur relatively small increases, no specific remediation may be necessary. At the higher end, however, it might be desirable to soften the blow, permitting electricity customers to adjust their expectations and behavior gradually by using phase-in techniques similar to those used in ratebasing expensive new generating units.[22] With such a technique, a transition to complete full-cost dispatch could be effected over several years. System-specific studies of the revenue requirement impacts as well as the environmental benefits of full-cost dispatch should be conducted, so that appropriate action for dealing with rate impacts can be formulated, if necessary.

XI. Cost Allocation in Power Pools

The increase in energy costs resulting from use of full-cost dispatch affects not only how rates are set for ratepayers; where multiple utility systems are dispatched as part of a central power pool, the increase in costs also will affect allocation of dispatch costs among the utilities.

Implementation of full-cost dispatching is best undertaken at the power pool level, as is conventional economic dispatch. This would permit the greatest level of flexibility and, thereby, overall economies in providing energy across several utility service territories. Addition of variable environmental costs to variable direct costs could, however, entail some distributional problems, even as it realizes overall societal economies. As noted earlier, total direct costs of supplying power will tend to increase when shifting to full-cost dispatch.

For a single utility, this is a matter between the utility and its ratepayers, mediated by the regulatory process. Both the direct costs and the environmental benefits (or some share thereof) would accrue to the utility's customers.

Within a power pool, on the other hand, full-cost dispatch could cause the increase in direct

costs to be borne disproportionately by the member utilities (and, thus, their ratepayers). This would tend to occur if the lower polluting plants were distributed disproportionately among the utilities in the pool. A concern for fairness to these utilities and their customers could be seen as being in contradiction with the goal of overall societal efficiency.

There are means to deal with these potential transfer problems without abandoning the goal of overall societal efficiency. A sharing of the additional costs on a pro rata basis would be the simplest procedure. However, this approach might provide insufficient incentive for individual utilities to improve their system's emissions characteristics. A more carefully designed approach may be necessary. Such a procedure could follow the basic logic and structure of allocational protocols already in place at power pools.

In the NEPOOL, for example, an overall reserve margin target is established for reliability purposes, to which member utilities are expected to contribute their capability responsibilities. These capacity requirements are based primarily on relative contributions to the pool-wide peak. This pro rata distribution is modified by member system-specific characteristics reflecting the relative reliability (forced outage rates, etc.) of their systems. Since capacity shortfalls are paid into a pool fund using this scheme, there is some incentive for members to improve their system reliability. This NEPOOL system is called the Performance Incentive Program (PIP).

NEPOOL also has a system to allocate the benefits of pool-wide economic dispatch. As full-cost dispatch is a direct extension of direct-cost dispatch, the procedures in place for allocating the benefits of pool-wide dispatch could serve as a starting point for a similar system with full-cost dispatch at the power pool level. However, it is important that such a system not penalize sharply those utility systems that have relatively cleaner generation but higher direct operating costs. The existing allocation system could be modified to ensure a fair allocation of the extra costs of full-cost dispatch on a pool-wide basis.

Consumers would then be presented with correct price signals, rather than the artificially low prices.

Finally, it is important to note that there are local environmental impacts of power plant generation that could be affected by full-cost dispatch. If global environmental costs (i.e., the costs of loadings) rather than site-specific environmental costs are added to direct operating costs, there could be some increased local impacts even as overall emissions and societal costs are reduced. This could cause new problems of fairness and transfers that would need to be solved by participants.[23] At least, local emissions or concentration limits could be followed, thereby constraining somewhat flexibility at the global emissions level.

XII. Collecting the Environmental Costs

Despite our concern with allocation and the implementation of a full-cost dispatch system, ultimately we do wish to encourage rather than suppress a system that obeys the "polluter pays" principle, both as a matter of assigning responsibility and to affect behavior appropriately. After phase-in, if any, the full societal cost of fuels for electric energy generation would be seen by electric utility planners and system operators, while the higher direct costs of their planning and operating decisions would be seen by electricity consumers.

But our approach implies more: the full cost of electricity production should be borne by electricity consumers. Rather than merely imputing external costs to their sources in system operating protocols without actual collection from ratepayers (phantom costs), the polluter pays principle and the goal of overall societal efficiency suggests that these costs actually be collected (real costs). Consumers would then be presented with correct price signals, rather than the artificially low prices that result from only imput-

ing external costs to planning and operating decisions.

By collecting actual externalities co the energy-related decisions of both electricity consumers (through increased conservation and fuel switching) and utilities (through changed priorities for dispatch and power procurement) could become more efficient from a total cost standpoint, to the degree that these decisions are price elastic. Moreover, modified (i.e., decreased) consumption can, in turn, affect planning decisions. Inclusion of externality costs in rates would be a consistent way to incorporate valuation of external costs and the goals of such valuation in utility and customer behavior.

Revenues collected from such a system could be placed in a fu that would be used to remediate the very problem that was the source of those revenues: the emissions of pollutants. Such remediation could include investments in pollution control, in environmental remediation, in conservation and renewables, in further research on environmental damages, damage costs and control techniques, and in other related options. Of course, the design and administration of such a system would require careful thought to ensure that it meets its objectives. One possible system could be based on competitive bidding for opportunities to pursue the pollution prevention and environmental damage reduction o ves of the fund.

A similar approach that is receiving attention with regard to CO_2 is to ascribe pollution taxes to energy purchase prices. This has the merit of being economy-wide, crossing all sectors in a consistent manner.

XIII. Conclusion

Over the past few years, regulators and to some extent utilities have been giving increasing attention to the inclusion of environmental externalities in

electric resource planning. While much work remains to be done on this important issue, we believe the time is ripe to extend such efforts beyond planning to utility operations. Planning can only go so far, since it is the use of existing facilities that determines the level of environmental pollution from electric generation.

We have proposed here what we believe to be the most reasonable method for including environmental externalities in utility operations: full-cost dispatching. We recognize that a range of issues must be addressed before such a system can become widely implemented. The technical issues are, we believe, more easily addressed than the allocational issues.

Regulators, in conjunction with utilities, environmental groups, consumer advocates, and other interested parties, must determine what costs are to be imputed to which pollutants for dispatch purposes (an issue that must also be addressed with regard to planning), what operational constraints will need to be identified before altering the dispatch, and how additional operating costs will be allocated across customer classes and utilities in power pools.

From a societal perspective, it is very expensive to continue to dispatch electric facilities according to traditional economic practice. While implementation of full-cost dispatch will not be a simple matter, the large potential benefits to society make the effort very worthwhile. ■

Footnotes:

1. An externality can involve impacts on a different segment of the population or a different geographical or political region than that receiving the energy services (e.g., acid gas emissions or the import of hydropower from James Bay to New England). It can also involve impacts on later generations. Finally, even within a given spatial and temporal boundary, externalities can be said to exist where the decision calculus ignores important impacts (whether on society directly or on other species or habitats).

2. We have analyzed the potential for improving the habitat through modifications to operating practices. *See* Bartels, Carlton and Bernow, Regulating the Kingsley Hydro-Electric Facility and Dam to Provide Scouring Flows on the Platte River, Tellus Inst.

Rep. to the Nat'l. Audubon Soc'y., Aug. 1989.

3. For example, the EPA currently requires that new coal-fired power stations have flue-gas desulfurization equipment (scrubbers) in order to limit sulfur dioxide emissions. The costs of installing and operating the scrubbers are then paid by the plant's owner. Electric utility planning studies now include the costs of scrubbers in deciding upon the most economical type of future capacity addition. In addition, the incremental cost of operating the scrubber is considered by system dispatchers in determining the optimal use of the facility.

4. The new amendments to the Clean Air Act will indirectly address existing facilities, since they impose a national emissions target and provide for trading allowances which may be used by existing or new facilities.

5. *See* Fl. Power and Light Co., Petition to Determine Need for Electric Power Plant 1993-1996, 1989..

6. *See* S.D. Cohen, J.H. Eto, C.A. Goldman, J. Beldock, and G. Crandall. *Environmental Externalities: What State Regulators are Doing*, THE ELEC. J., July 1990.

7. All nuclear and most coal-fired generating plants are also subject to operating constraints that require them to be baseloaded once they are placed in operation. On the other hand, hydroelectric dispatch may be limited by water conditions and other operating constraints.

8. New combined-cycle units burning natural gas have recently become attractive options for baseload and intermediate cycling service because of their high fuel efficiency (low heat rate) and resulting low variable costs.

9. Of course, when very high dispatch costs might otherwise be incurred, non-dispatch-related options become relatively more attractive.

10. A simple example of emissions constrained dispatch is the operating restriction of the Powerplant and Industrial Fuel Use Act of 1978, P.L. No. 95-620. This law specified that natural gas could be used in a new power plant only if annual operation was constrained to 1500 hours or less (subject to certain exemptions). These restrictions were enacted as a means of reducing national dependence on oil and gas.

11. N.Y. STATE ENERGY OFF., N.Y. STATE DEPT. OF PUBLIC SERVICE, AND N.Y. STATE DEPT. OF ENVT'L. CONS., N.Y. STATE ENERGY PLAN (1989).

12. J.S. Heslin and B.F. Hobbs, A State-Level Probabilistic Production Costing Analysis of SO_2 Emissions Reduction Strategies for Ohio: Effectiveness, Costs, and Regional Economic Impacts, Case W. Res. Univ., 1990.

13. This approach is described in detail in S. B[illegible]w and D. Marron, Valuation of Environmental Externalities for Energy Planning and Operations: May 1990 Update, Tellus Inst., May 18, 1990.

14. Mass. Dept. of Pub. Util., Investigation by the Dept of Pub. Util. on its own motion into proposed rules to implement integrated resource management practices for electric companies, Docket No. DPU 89-239, Final Order, Aug. 31, 1990.

15. Note that if the least-emissions dispatch were dealing with only one pollutant, the valuing would not be necessary. With one pollutant, we could simply dispatch to minimize emissions of that type. With multiple pollutants, however, we need a means of valuing each relative to the others. The emissions values (in dollars per pound) provide a convenient way to specify relative values. Other ways are possible. For example, we could say that one ton of SO_2 emitted is 70 times as bad as one ton of CO_2, that one ton of NO_x is four times as bad as one ton of SO_2, and so on. This would be equivalent for the least-emissions dispatch case. Using a monetary definition, however, offers a convenient measure of badness, and also allows easy comparison of direct costs and emissions costs. It also permits aggregation of environmental costs across different pollutants.

16. Note that total dispatch costs, which include nuclear and hydro plants, have increased by less than 9%, since we assume that non-fossil generation is unaffected. Further, note that total electricity costs have increased by substantially less than 9%, since total costs include fixed costs etc.

17. "Environmental 'Dispatch' Impossible, Says New England Electric Executive," Elec. Util. Week, July 2, 1990.

18. It could also imply that retirement (or reserve shutdown status) would be desirable for such units if added environmental costs were used in system planning and operation.

19. S. Bernow, Excess Capacity and Cost Benefit Analysis of the Palo Verde Generating Station, Direst Testimony before the Ariz. Corp. Comm. in Docket No. U-1345-85-367, Feb. 1987.

20. ELEC. POWER RES. INST., TECHNICAL ASSESSMENT GUIDE, VOL. 1: ELECTRICITY SUPPLY (1986).

21. R.H. Williams and E. D. Larson, *Expanding Roles for Gas Turbines in Power Generation*, in ELECTRICITY (T.B. Johannsen and R. Williams, eds., U. of Lund (Swe.), 1988). *See also* telephone conversation with D. Todd, G.E. Power Systems, Schenectady, N.Y.

22. It is noteworthy that our hypothetical system showed large benefits at externalities monetized for dispatch at a fraction of their full values.

23. If full-cost dispatch incorporated simulations of transport, exposure, dose-response, and damage valuation, global and local impacts could receive their appropriate relative treatment.

Annu. Rev. Energy 1989. 14:131-71
Copyright © 1989 by Annual Reviews Inc. All rights reserved

ENERGY AND TRANSPORTATION IN THE UNITED STATES

Marc Ross

Physics Department, University of Michigan, Ann Arbor, Michigan 48109
and

American Council for an Energy Efficient Economy, 1001 Connecticut Avenue NW, Washington DC 20036

INTRODUCTION

Transportation activities accounted for 28% of all US energy use in 1987, or 21.3 quadrillion Btu (quads). More than 97% of this energy was in petroleum products. Moreover, 63% of all petroleum is used directly for transportation, and much of the petroleum used in other sectors is in the form of by-products of gasoline, diesel fuel, and jet fuel production. In addition, while energy use for transportation grew at the relatively moderate average rate of 1.2% per year in 1972–1987, all other sectors slashed their use of petroleum, so transportation's share is larger than in the past (1).

What is the story behind these numbers? The past 15 years have been tumultuous. The oil embargo of the fall of 1973 led to shortages and price controls. The Motor Vehicle Information & Cost Savings Act of 1975 introduced the Corporate Average Fuel Economy standards. The second oil shock, accompanying the Iranian revolution of 1979, led to long lines at filling stations and high fuel prices. Then, as governments, equipment manufacturers, and consumers around the world moved toward more efficient use of petroleum, and oil producers moved to increase production, oil prices fell and fuel again became plentiful. The typical price of gasoline in the United States is now about the same as in 1972, after accounting for the general inflation.

But we have hardly returned to 1972 conditions. Our capital, human knowledge, institutions, and equipment have changed forever. Our un-

0362-1626/89/1022-0131$02.00

derstanding of transportation energy issues—supplies of petroleum, the efficiency of its use, the side effects of its extraction and use, and even alternatives to the present energy-using system—is far deeper today than before the adventures of the past 15 years.

In this paper, energy use in all areas of transportation is briefly analyzed. Then a coherent subset of issues facing the largest of the activities, personal passenger transportation based on petroleum fuels, is explored in depth: the reasons for past and future growth in driving, the past developments in fuel economy, and the possibilities for change in the next one to two decades. This look ahead involves (*a*) the technical potential for further improvement in fuel economy and reductions in air pollution, (*b*) the role of the market in these areas, and (*c*) the role of public policies.

This narrow focus has been adopted to enable the exploration of several perspectives on one area of transportation in some depth. Other fuel options and other transportation modes are of course important, and are very briefly discussed at the end of this paper. Nevertheless, petroleum-fueled personal passenger transportation is the largest energy user, accounting for 58% of transportation energy use, and will remain so for the period in question. Although there are alternatives of considerable interest, there will be no rush to embrace them on a national scale.

ACTIVITY AND ENERGY USE, 1972–1985

In this section, energy use in 1985 is first disaggregated. In each subsector, energy use is expressed as the product of a level of activity and an energy-intensity. For example, for automobiles the activity selected is vehicle-miles traveled and the energy-intensity is then expressed in Btu per mile. Total energy use is a sum of such products:

$$E = \sum_i A_i(EI)_i \qquad 1.$$

Using the simple but elegant Divisia technique, the change in energy use over time is then decomposed into a change due to changed activity levels and a change due to changed energy-intensities.

Transportation in 1985

There are several sources of data on energy and activity in transportation; this richness of data makes the sector more congenial for the energy analyst than any other sector except manufacturing. Using these sources, a group at Oak Ridge National Laboratory has disaggregated transportation energy use (Table 1.10 of Refs. 2 and 3).

One area of transportation that needs a more ambitious disaggregation is

trucks. The light truck has been the most rapidly growing category of transportation, more so than air travel. It is, how[illegible] primarily a categorization problem. Trucking is dominated in fuel use by light trucks (pickups, vans, and jeep-like vehicles, under five tons); about three fourths of light trucks, in turn, are now being used as cars (4). A good analysis requires disaggregation of trucking into light trucks used as personal passenger vehicles, light trucks used for freight, 5–13-ton trucks, and very heavy trucks. (In the tables in this article the last two are grouped together as heavy trucks.) Among the reasons for the shift to pickup trucks as passenger vehicles is the decreasing number of passengers in typical trips. The average household size declined from 3.14 in 1970 to 2.66 in 1987, and the average occupancy of automobiles declined from 2.2 to 1.5 or 1.6. Light trucks also appear to be more durable than cars. The average light truck is scrapped after 14 years, while the average car is scrapped after 10 (Table 2.11 of Refs. 2 and 3). Other advantages of light trucks may flow from the fact that they are more lightly regulated with respect to fuel economy, emissions, and safety than cars.

Two sources of first-hand data permit the disaggregation of trucking: the Census's Truck Inventory and Use Survey (TIUS) of 1982 (4) and the 1985 Residential Transportation Energy Consumption Survey (RTECS) of the Energy Information Administration (EIA) (5). The activities and energy use of highway vehicles are obtained from these sources (Table 1). In preparing this table, an inclusive definition of light trucks, as to types of vehicle, is used. In some other studies, light trucks comprise a more restricted group of vehicles. This difference largely explains the larger activity and energy use by light trucks (and smaller by heavy trucks) in Table 1, compared to the results of some other studies (2, 8, 9, 10).

Table 2 shows energy, activity, and energy-intensity in detail for all of transportation in 1985. The main characteristic is the dominance of personal passenger vehicles. Passenger transportation dominates freight in energy use, and personal vehicles dominate passenger transportation. Personal passenger vehicles account for 58% of all transportation energy use and for 85% of all passenger-miles (assuming a personal vehicle occupancy of 1.6 in 1985). Commercial air carriers provide 11% of the passenger-miles, while buses and trains together provide only 4%.

The personal vehicle is more energy intensive than the other forms of passenger transportation, but not by as much as many think. The average car is shown in Table 2 to have an energy-intensity of 7100 Btu per mile (an in-use fuel economy of 17.6 mpg). An urban transit bus has an energy-intensity of 3600 Btu per passenger-mile (Table 2, note e). So a car with two people, or a car with one person but twice the average fuel economy, not only goes where and when you want, but has roughly the same energy-intensity per passenger-mile as an urban bus. (The low energy-intensity for buses in Table

Table 1 Highway vehicle activity and energy use, 1985

	Vehicles[a] (millions)	Miles/vehicle (thousands)	Vehicle-miles[b] (trillions)	mpg	Energy (quads)
Automobiles					
household	104	9.7[c]	1.01	17.2[d]	7.35
fleet	10.5[e]	27	0.28	20[f]	1.78
passenger light trucks[g]	28.7[h]	9.6[c]	0.28	13.3[d]	2.60
freight light trucks[i]	9.6[b]	10.5[j]	0.10	12[j]	1.05
heavy trucks[k]	4.1	23	0.035	5.4	2.40
buses[l]	0.6	10	0.006		0.15
motorcycles			0.009		0.02
Total			1.78		15.35[m]

[a] Automobile and truck totals based on R. H. Polk data (pp. 28, 29 of Ref. 6)
[b] In approximate accord with data from the Department of Transportation (7), (p. 53 of Ref. 6)
[c] From (5), but slightly less to account for some of those vehicles used by households being fleet automobiles or freight light trucks with higher use.
[d] (5)
[e] (Table 2.35 of Refs. 2 and 3)
[f] Estimate between new-car in-use fuel economy of 22 mpg and household fuel economy of 17 mpg.
[g] Includes pickups, vans, and jeep-like vehicles.
[h] For number of light trucks, subtract heavy trucks from total. Assume 75% of light trucks are used for personal passenger transportation. This assumption is based, for example, on 1982 TIUS results that 73% of light trucks do not carry freight (4). (Freight includes craftsman's tools.)
[i] Under 10,000 lbs.
[j] Miles per vehicle adjusted is up about 10% and fuel economy down about 10% from household trucks (5).
[k] Based primarily on summary of TIUS (Table 2.39 of Refs. 2 and 3). Number of heavy trucks based on 3.58 million in 1982 (TIUS), addition of 5.4 million trucks in 1982–1985, and sales fraction of heavy trucks of 9% in the period (pp. 10, 11 of Ref. 6). 1985 miles per vehicle, vehicle-miles, and fuel economy generated assuming (*a*) that miles per vehicle-year of trucks over 26,000 lb. remained at 36.6 thousand, and those of trucks between 10,000 and 26,000 lb. remained at 9.5 thousand (TIUS), and (*b*) that 1982 fuel economies improved 2%. The results of this exercise for 1985 is 76 and 19 million vehicle-miles, and 27.5 and 19.1 thousand Btu per mile, for the heavier and less heavy groups of trucks, respectively. The resulting energy use is: diesel 1.95 and 0.08, gasoline 0.10 and 0.27 for the two groups of heavy trucks, respectively, in quads (quadrillion Btu).
[l] Tables 2.47 and 2.48 of Refs. 2 and 3
[m] This quantity (and gasoline and diesel totals) was used as a control total to make minor adjustments.

2 is due to school buses and the shaky assumption that their average passenger load is 20. The average load of the urban transit bus is 17.) The energy-intensity of certificated air carriers is also not as great as one might, at first, think.

Freight energy use is also dominated by highway vehicles, but freight activity measured in ton-miles is dominated by nonhighway modes. The nonhighway freight modes are much less energy intensive than heavy trucks. Note that gas pipelines are fairly energy intensive, however; a gas is much more difficult to pump than a liquid.

The Change from 1972 to 1985

Many of the transportation activities have been tracked in consistent or nearly consistent data series since 1970 and before. For this paper, the period

Table 2 Transportation activity and energy use, 1985[a]

Mode	Energy (quads)	Activity[b] unit	Activity (trillions)	Energy-intensity (thousand Btu per unit)
Passenger				
automobiles[c]	9.16	VM	1.29	7.1
light trucks[d]	2.60	VM	0.28	9.3
buses	0.15	PM	0.11[e]	1.4[e]
rail	0.05[f]	PM	0.015	3.5[f]
air	1.61[g]	PM	0.336	5.0[g]
subtotal	13.57			
Freight				
light trucks[d]	1.05	VM	0.10	10.4
heavy trucks	2.40	TM	0.7	3.4
rail[h]	0.45	TM	0.91	0.49
marine[i]—domestic	0.30	TM	0.89	0.34
—foreign	0.75	lbs	1.54	0.5
pipelines[j]	0.55[f]	TM	0.26	2.1[f]
subtotal	5.50			
Miscellaneous				
military	0.70			
recreational boats	0.22			
general aviation	0.14			
subtotal	1.06			
Grand total	20.12			

[a] Adapted from Table 1.10 (Refs. 2, 3) and Table 1.
[b] PM, passenger-miles; VM, vehicle-miles; lbs, pounds shipped; TM, ton-miles.
[c] Includes motorcycles
[d] Under 10,000 lbs.
[e] Assumes occupancy of 20 passengers in school buses. The energy-intensity of urban transit buses is stated to be 3.6 thousand Btu/PM.
[f] Includes losses in generating and distributing electricity.
[g] Freight-activity, responsible perhaps for 0.05 quad, is included. Energy use is purchases of domestic fuel by domestic and international carriers. The energy-intensity is based on total fuel used, roughly corrected for freight activities.
[h] Table 3.9 of Refs. 2 and 3.
[i] Tables 3.5 and 3.6 of Refs. 2 and 3.
[j] Natural gas pipelines only. Activity is based on total consumption of natural gas (1) and assumed average transportation of 620 miles.

1972–1985 is selected for an analysis of trends. Energy consumption in 1972 and 1985, and average growth rates for activity during that period, are shown in Table 3. (It will be seen that our analysis does not require activities in different subsectors to be measured in the same units. Energy use measures must be commensurate across subsectors, however.)

Table 3 reveals the critical role of the light truck as a personal passenger vehicle. It also shows the growing importance of air travel, as well as the relatively slow growth of most freight activities. In the latter connection,

Table 3 Transportation energy use and activity, 1972–1985

	Energy (quads) 1972	Energy (quads) 1985	Activity means[a]	Growth rates (percent per year) activity	Growth rates (percent per year) energy-intensity[b]
Passenger					
automobiles	9.18[c]	9.16	VM	2.1[d]	−2.1[e]
light trucks[f]	1.11	2.60	VM	8.9	−2.0
(combined)	(10.29)	(11.76)	VM	3.0	−2.0
buses[g]	.11	0.15	PM	2	1
rail[h]	.04	0.05	PM	0.3	1
air[i]	1.30	1.61	PM	6.3	−4.6
subtotal	11.74	13.57			
Freight					
light trucks[j]	0.99	1.05	VM	1.9	−1.4
heavy trucks[k]	1.82	2.40	GNP[k]	2.5	−0.3
rail[l]	0.57	0.45	TM	0.9	−2.7
marine[m]—domestic	0.32	0.30	TM	2.9	−3
—foreign	0.69	0.75	T	1.6	−1
pipelines[n]	0.77	0.55	quads	−1.7	−1
subtotal	5.15	5.50			
Total[o]	16.90	19.07			

[a] VM, Vehicle-miles; PM, passenger-miles; TM, ton-miles; T, tons shipped; quads, quadrillion Btu (of natural gas consumed in the United States).

[b] Independent data for cars and to a lesser extent for light trucks, but energy-intensity trends are typically calculated as difference in growth rate between energy and activity.

[c] Table 1.13 of Refs. 2 and 3.

[d] Automobiles (excluding motorcycles) were driven 980 and 1290 billion miles in 1972 and 1985, respectively (7).

[e] Consistent with change from 13.5 to 17.8 mpg.

[f] The light truck VM in 1972 is the difference between total truck VM (7) and non-light-truck VM (Table 2 of Ref. 11). Thus it equals 260 − 90 = 170 billion. The fraction of these vehicles used as passenger vehicles in 1972 (0.534 from Ref. 11) is used to apportion the VM, yielding 91 billion VM for passenger light trucks. Fuel used is determined assuming that fuel economy improved 2% per year in 1972–1985, so fuel use for passenger light trucks in 1972 = (91/275) exp (13 × ln 1.02) × 2.60 = 1.11 quads, where 275 billion VM were driven in 1985.

[g] (Tables 2.45 and 1.18 of Refs. 2 and 3). The average occupancy of school buses is assumed to be 20.

[h] Tables 3.11 and 3.12 of Refs. 2 and 3.

[i] Table 3.1 of Refs. 2 and 3, corrected to domestic fuel purchases.

[j] Fuel use is based on assumed fuel economy of 10 mpg and VM from note f: (79/10) × 1.25 = 0.99 quads. Activity grows from 79 to 101 billion miles (Table 1).

[k] Fuel use for all trucks (Table 1.13 of Refs. 2 and 3) or 3.91 quads in 1972, from which 2.10 for light trucks (notes f and j) is subtracted. Activity is taken proportional to real GNP. An alternative would be ton-miles in intercity motor freight, which grew from 470 to 610 billion from 1972 to 1985 (p. 57 of Ref. 6).

[l] Table 3.9 of Refs. 2 and 3.

[m] (Tables 3.5 and 3.6 of Refs. 2 and 3). A universal 1% per year energy-intensity reduction is assumed for foreign.

[n] Natural gas pipelines only. No historical data is available on energy use for pipelines for petroleum or materials other than natural gas.

[o] Miscellaneous uses have been omitted from Table 1.

high value measures of trade and freight are increasing, tonnage measures are declining with respect to GNP. This reflects the growing share of consumption, in advanced industrial societies, accounted for by less materials-intensive, and therefore lighter, products (12).

The data in Table 3 has been set up to enable a Divisia decomposition. Define $G(X)$ to be the compound growth rate, measured in percent per year, of a quantity $X(T)$:

$$G(X) = (100/T)\ln[X(T)/X(0)]$$

with T in years; and define the weighted average growth rate:

The Divisia decomposition of Equation 1 is:

$$G(E) \approx \langle G(A) \rangle + \langle G(E/A) \rangle$$

where one should note

$$\langle G(E/A) \rangle = \langle G(E) \rangle - \langle G(A) \rangle$$

Here W_i is the time-average energy weight of the subsector:

$$W_i = 1/2[E_i(T)/E(T) + E_i(0)/E(0)]$$

[See Boyd et al (12a) for further details.] Equation 2 states that the average growth rate in energy use (approximately) equals the energy-weighted average growth in activity plus the average growth in energy-intensity. (For typical energy-use time series, the approximation is good to about 0.1% per year or better.)

The results of the analysis are summarized in Table 4. The behavior for transportation as a whole is the same as that for personal passenger vehicles alone: growth in activity at an average 3% per year, but a rapid decline in energy-intensity, so that energy use grew only 1% per year in this period.

The separate results for passenger and freight activity show what is not surprising to any observer of the US scene: travel is increasing rapidly, but so is the energy-efficiency with which it is provided. Freight activity in ton-miles has been increasing much less rapidly, a characteristic of an affluent and mature society. At the same time, it has proven more difficult to improve the

Table 4 Divisia analysis of energy used for transportation, 1972–1985

(growth rates in percent per year)

	Activity	Energy-intensity	Energy
Passenger	3.6	−2.4	1.1
Freight	1.7	−1.1	0.5
Total	3.0	−2.0	1.0

energy-efficiency of freight services. (The notes to Table 3 show that the freight data is much less complete and therefore the decomposition for freight is less reliable than that for passenger travel, but the essential picture is clear.)

If we want to understand these results, we must decompose and probe them further. What is responsible for the growth in travel? What is responsible for the decline in energy-intensity? In the next two sections these questions will be explored with respect to personal passenger vehicles.

TRENDS IN HIGHWAY TRAVEL

Vehicle travel continues to grow in spite of arguments that saturation is imminent. Figure 1 shows total vehicle-miles traveled, and Figure 2 total vehicle-miles per adult (i.e. total vehicle-miles divided by the population aged 16 and over). The data and a curve with adjusted parameters for income and fuel price effects are shown. The theoretical curve is almost proportional to real disposable income per capita, corrected by a moderate fuel price elasticity effect, representing an elasticity of −0.1 (indicating that a 10% increase in the fuel price induces a 1% decline in consumption). In a slightly different approach to these data, Werbos found a fuel price elasticity of −0.2 (14).

The decomposition of this trend in vehicle-miles will be based on information from the 1983 National Personal Transportation Survey (NPTS) on drivers and their driving (15). From our present perspective, however, 1983 was an unusual year because of the high fuel prices, with a real fuel price 42% higher than now, so in the following the amount of driving in that year will be corrected by a factor of $(1.42)^{0.15}=1.05$ (where the average of the two elasticities mentioned in the last paragraph is adopted). That is, about 5% more driving would have occurred in 1983 had gasoline prices been like those of 1986. This correction crudely represents the effect on vehicle-miles of the fuel price excursion of the late 1970s and early 1980s.

Just because income per person provides a good statistical fit to the general growth trend for driving does not mean it is a good interpretation. De-

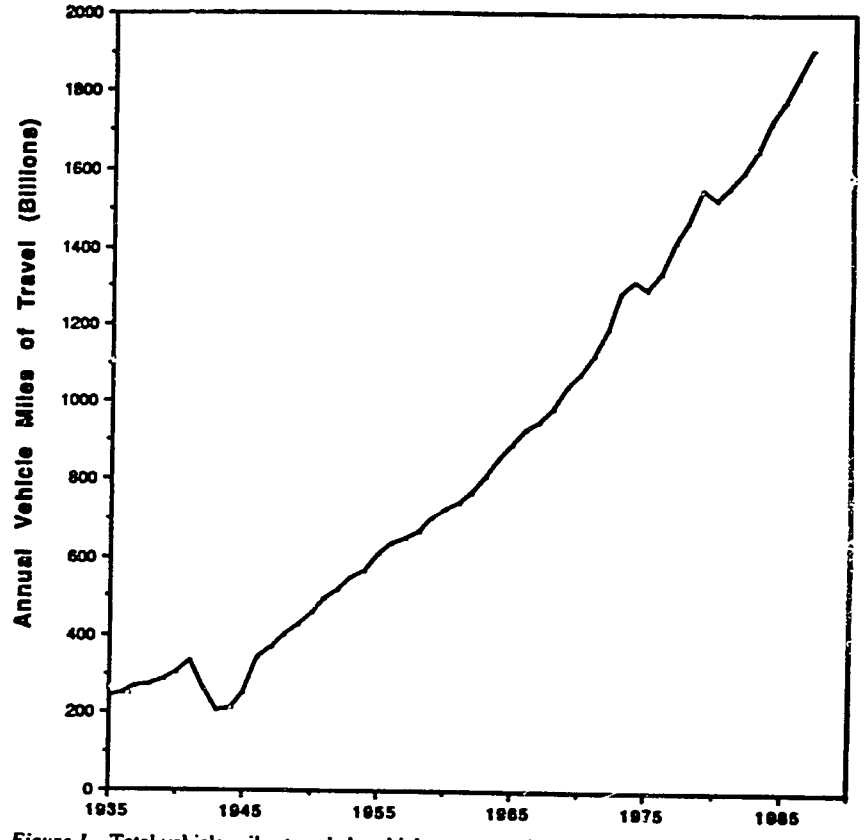


Figure 1 Total vehicle-miles traveled on highways annually (in the 12 months prior to January of the year shown). Source: (13)

mographics provide a more interesting perspective. Much of the growth in driving since the late 1960s is associated with women moving into the labor force and those women becoming drivers (Table 5). In 1969, 39% of adult women were employed; in 1983, 50% were employed. In 1969, 74% of employed women had drivers licenses; in 1983, 91% did. The relative increase in licensed drivers accounts for half the growth in driving per adult shown in Figure 2 between 1969 and 1983.

From 1969 to 1983 (corrected), personal vehicle-miles traveled grew at a rate of 3.5% per annum (p.a.). This growth can be described in terms of the 1.8% p.a. growth rate in number of adults, a growth of 0.6% p.a. due to shifts in employment and the changing role of women discussed in the previous paragraph, and the residual, a 1.1% p.a. growth in driving per licensed driver.

In the next decade growth in the number of adults will slow dramatically, as

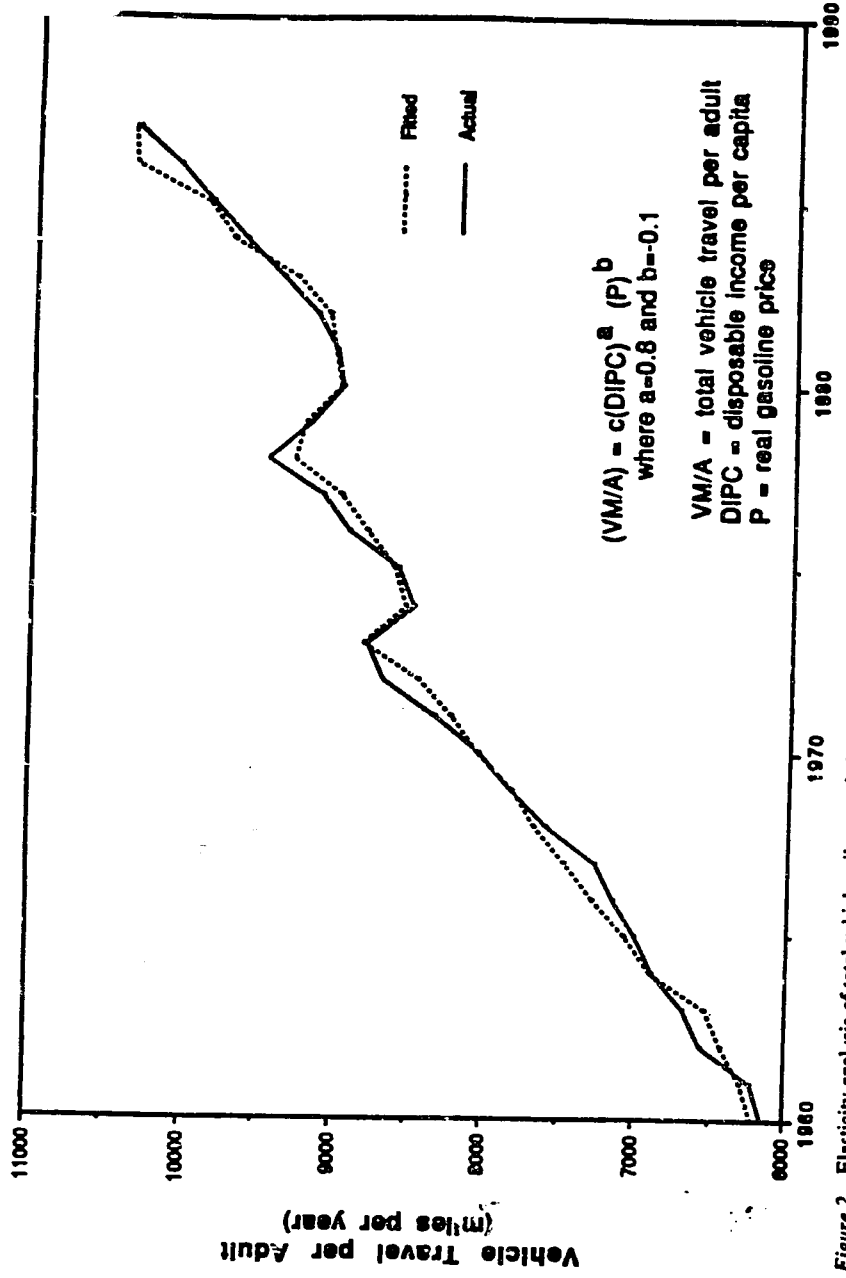


Figure 2 Elasticity analysis of total vehicle-miles traveled per adult. The analysis is similar to that of (14), but differs in details as well as including more recent data. Source of primary data: (13)

Table 5 Drivers licenses and driving, by sex and employment

	1969		1983		
	% of adults	% with license	% of adults	% with license	Annual miles per driver (1000s)
Employed full time or part time					
Male	36.3	93.5	34.4	95.8	15.9
Female	20.8	74.1	26.0	91.1	7.7
Not employed					
Male	10.5	64.8	13.2	76.0	7.7
Female	32.4	54.9	26.4	64.2	4.5
Total	100	75.1	100	83.6	10.3

Source: (15)

will the effect of increasing employment and licensing of women (because they have already moved so far toward matching men in this respect). If men and women in 2000 have the employment-licensing characteristics of men in 1983 (in the various age groups) and if the average growth rate of driving per licensed driver remains the same as for 1969–1983, then vehicle-miles traveled will grow an average of 2.4% per year from 1983 to 2000. This slower growth should be felt soon, after the response to the fuel price reductions of the mid-1980s is complete—if the analysis is accurate.

The projection of slower growth in road travel is supported by two other facts. The distance driven per driver is unlikely to increase much further for the predominant cohort, employed men in their prime years (25–54). This group already drives an average of 18,000 miles per year or about 1 1/2 hours per day. Moreover, as shown in Figure 3 for all employed men, this driving pattern is essentially independent of income (unpublished analysis of the NPTS data by Anant Vyas). (In the past, evidence has been offered for a fairly strong income dependence of vehicle-miles per household, but that is of less interest than the weak dependence shown, which is for vehicle-miles per driver.)

On the other hand, there is no hint that the information revolution will reduce the amount of travel. If anything, just as more information seems to lead to more use of paper, better information and communication may lead to increased travel. The cellular phone may, for example, lead some people to spend more time in their vehicles. More important, the growth in part-time work and business services is leading people to spend more time on the road. These developments are abetted by the information revolution, but are also partly due to a relative decline in full-time work with good pay.

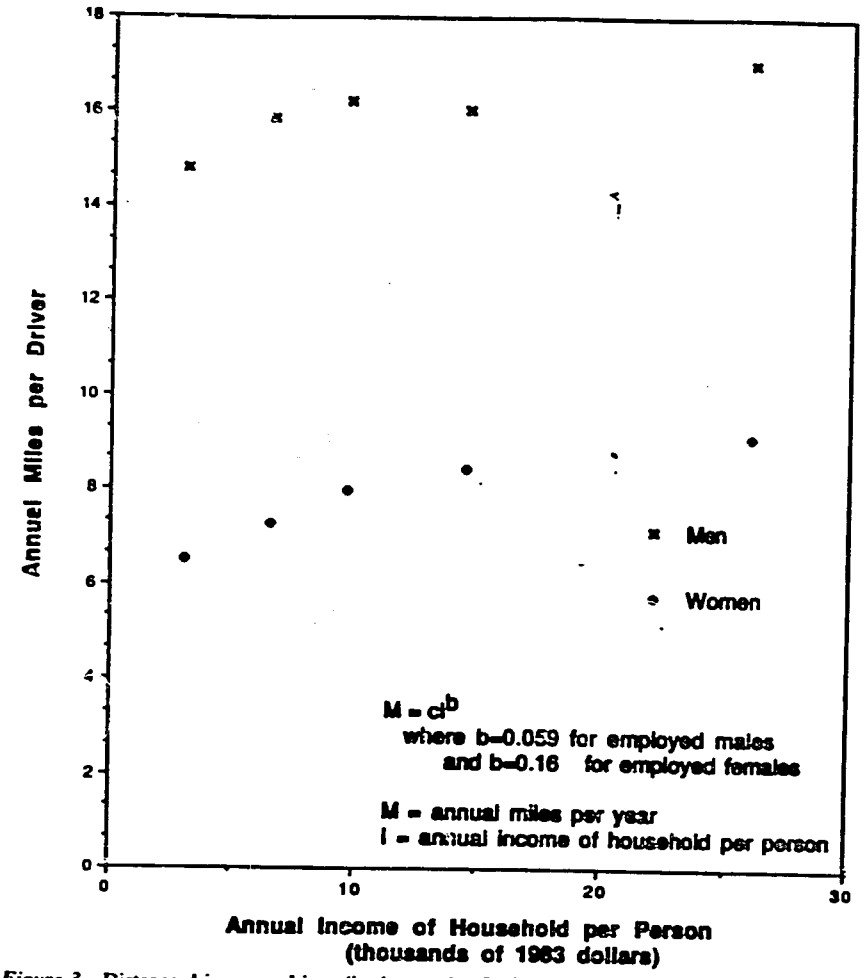


Figure 3 Distance driven per driver (in thousands of miles) vs household income per person, showing the small income elasticity of driving in the United States. Data is for 1983 from (15)

The description of vehicle-miles traveled on the basis of the number of drivers, just presented, is in contrast to one based on the vehicles in use—an approach that has been widely used in forecasting. The trouble with using miles per vehicle for forecasting is that, in the United States, a fundamental shift in the use of private vehicles is now beginning to take place. The number of households with more vehicles than drivers is becoming large. This trend toward extra, probably special-use, vehicles may well continue strongly as vehicles are kept in service longer and the adult population grows more

slowly. (For example, the median age of cars in use has increased two years since the early 1970s.) The growth in the number of vehicles and, especially, their use is thus difficult to forecast accurately.

In conclusion, recent growth in vehicle-miles has been fueled by the baby boom cohort entering adulthood and the changing role of women. Those sources of growth are saturating, so total vehicle-miles should start to grow more slowly. Nevertheless, there is still considerable room for growth in vehicle-miles.

RECENT TRENDS IN FUEL ECONOMY

The Mix of Vehicles Purchased

Since its nadir of about 14 mpg in 1973, the fuel economy of new cars has approximately doubled to 28 mpg. (These new-vehicle fuel economies are nominal, i.e. laboratory measurements. Their relation to in-use fuel economy is discussed below.) The average fuel economy of new light-duty vehicles (both cars and light trucks) has, however, only increased one mpg since 1981 (Figure 4). One important reason for slower growth in fuel economy compared to the previous period is that consumers are switching to light trucks, and their fuel economy is lagging.

The early 1970s saw a shift to smaller cars. In spite of frequent remarks to the contrary, however, consumers are not switching back to larger cars (Figure 5), although they did, to a small extent, in the early 1980s. If the size of cars is specified in terms of interior volume, then one finds that the sales-weighted average volume has hardly changed in the past decade. The Environmental Protection Agency (EPA) interior volume averaged 109 ft^3 in 1978, fell to a low of 104 ft^3 in 1980, and is now steady at 108 ft^3.

In addition, while there is considerable variation in fuel economy within each automobile size class, especially in the small classes, the average fuel economies for each class vary only 30% from the smallest to the largest size class (Figure 6). This is in part due to the low fuel economies of some heavy high-powered cars that are styled as sport cars and so have low interior volume, with the result that the average fuel economy in the smaller classes is held down. In other words, while the very highest-fuel-economy cars are indeed small, buying the average small car does not ensure getting a high fuel economy.

With these observations in mind, it is not surprising that a Divisia analysis of automobiles by size class shows that only one-tenth of the fuel-economy improvement in new cars from 1976 to 1988 was due to consumers' shifting to smaller cars, while the lion's share came from fuel-economy improvements within each size class (Figure 7). This analysis is, however, somewhat sensitive to how the size classes are defined.

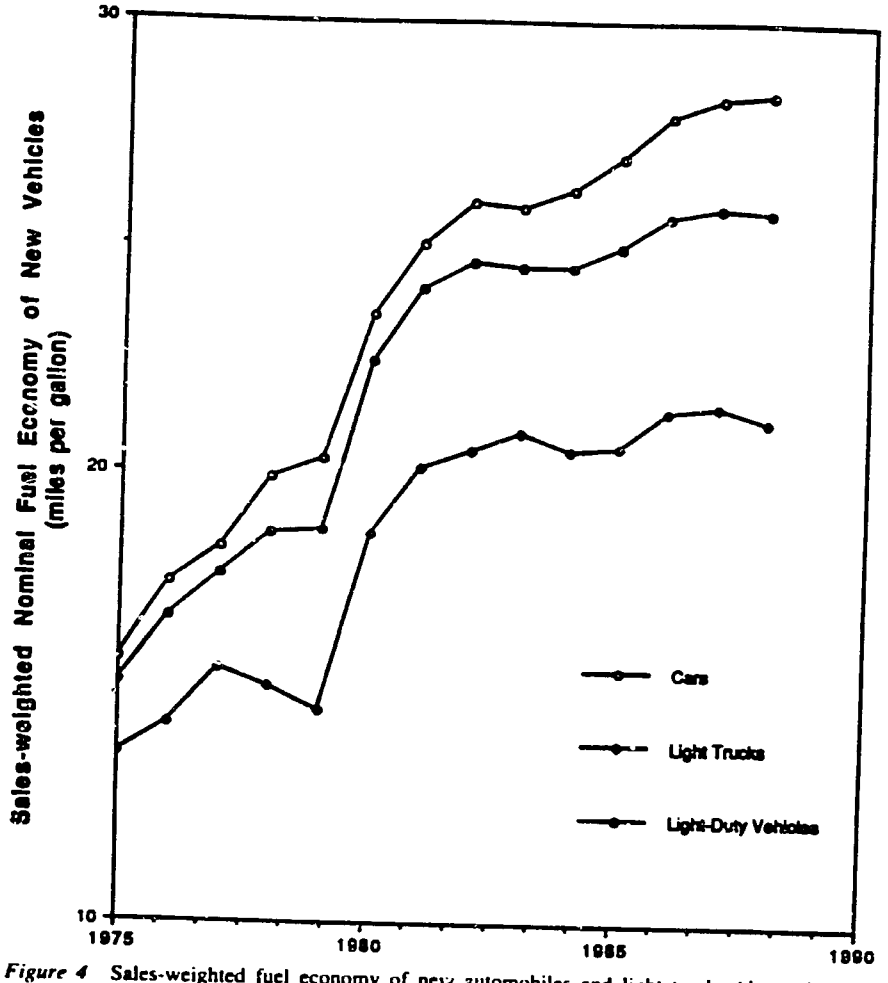


Figure 4 Sales-weighted fuel economy of new automobiles and light trucks (domestic and foreign) and the composite fuel economy of both. The nominal 55%/45% city-highway fuel economy is shown. Source: (16, 17)

What happened within each size class is that new models with higher fuel economy were introduced, replacing or taking market share from old models. In recent years, this process has weakened in the compact and subcompact classes, especially for foreign cars. This weakening explains the slowed progress in fuel-economy improvement for cars since 1982, shown in Figure 7. The introduction of models with higher fuel economy has continued in the intermediate and large classes, explaining the recent improvement.

The progress in each size class (sales-weighted average) is shown in Figure

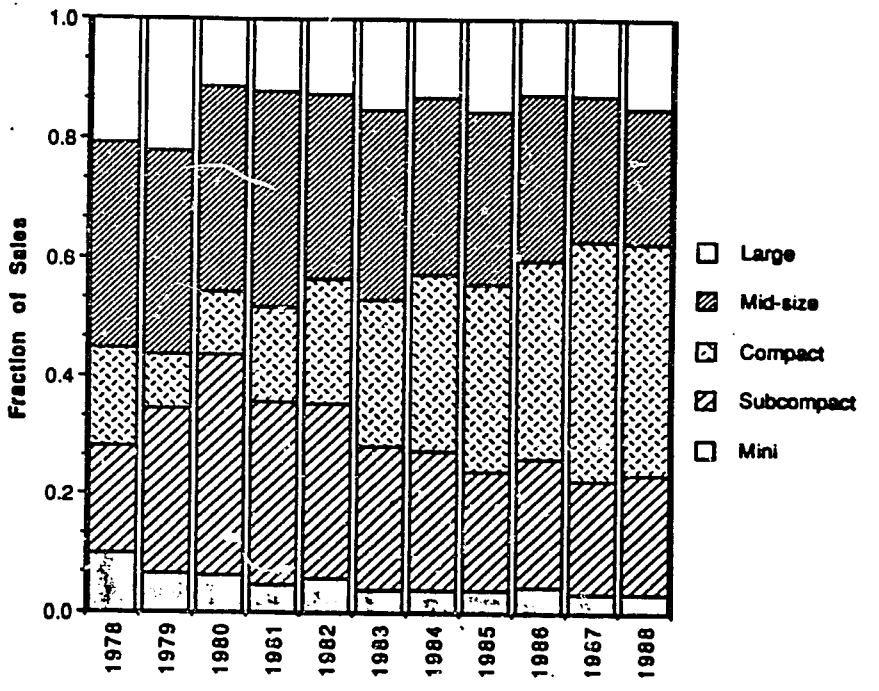


Figure 5 Fraction of sales per automotive size class (EPA interior volume basis). Figure inspired by (18), data from (19, 20)

8 for four car sizes and all six truck sizes. The failure of most of the truck classes to improve as much as the cars is evident. Much more of the improvement in the overall fuel economy of trucks was due to the shift in sales to smaller vehicles, a shift that accompanied the boom in passenger light trucks, than was the case for cars.

Design, Engineering, and Trade-offs

The major fuel-economy improvements in the past decade can be grouped into three components: propulsion-system engineering, other elements of vehicle design, and trade-offs.

Engineering improvements are exemplified by the remarkable 36% increase in power per unit of engine size, or displacement (Table 6). Engine displacement has long been used as a surrogate indicator of power, but engineers have found many ways to loosen the connection.

Through improved design and use of new materials, the ratio of weight to interior volume of cars has been reduced an average of 16% over the past

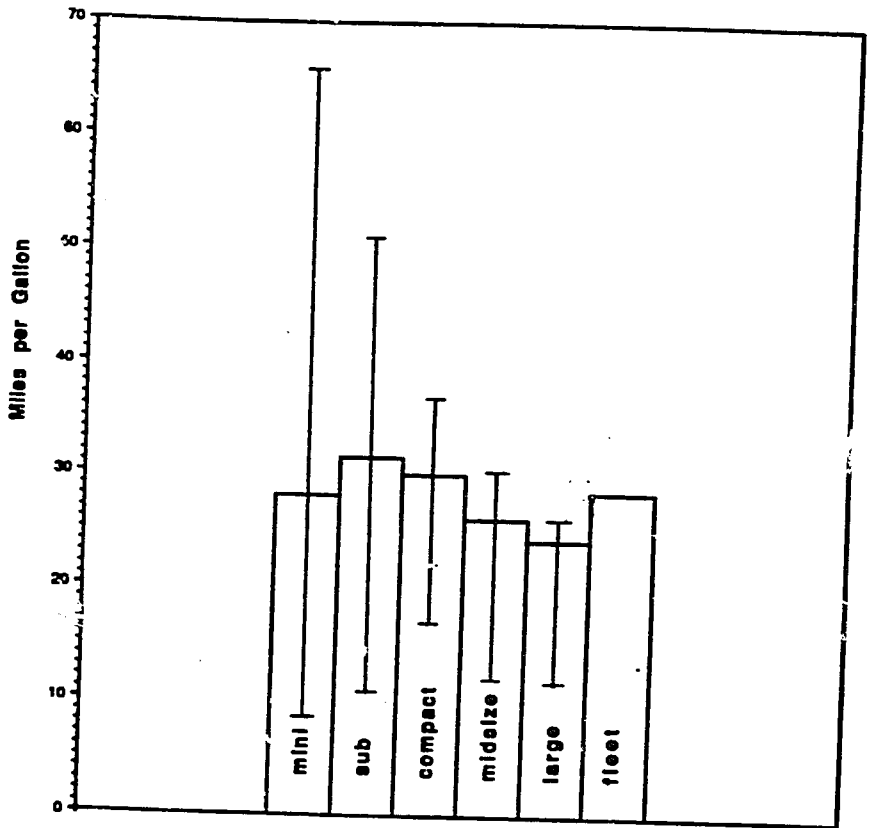


Figure 6 Sales-weighted fuel economy of cars by size class (nominal fuel economy, EPA interior volume classes). Bars show the highest- and lowest-fuel-economy models in each class. Source: (16, 17)

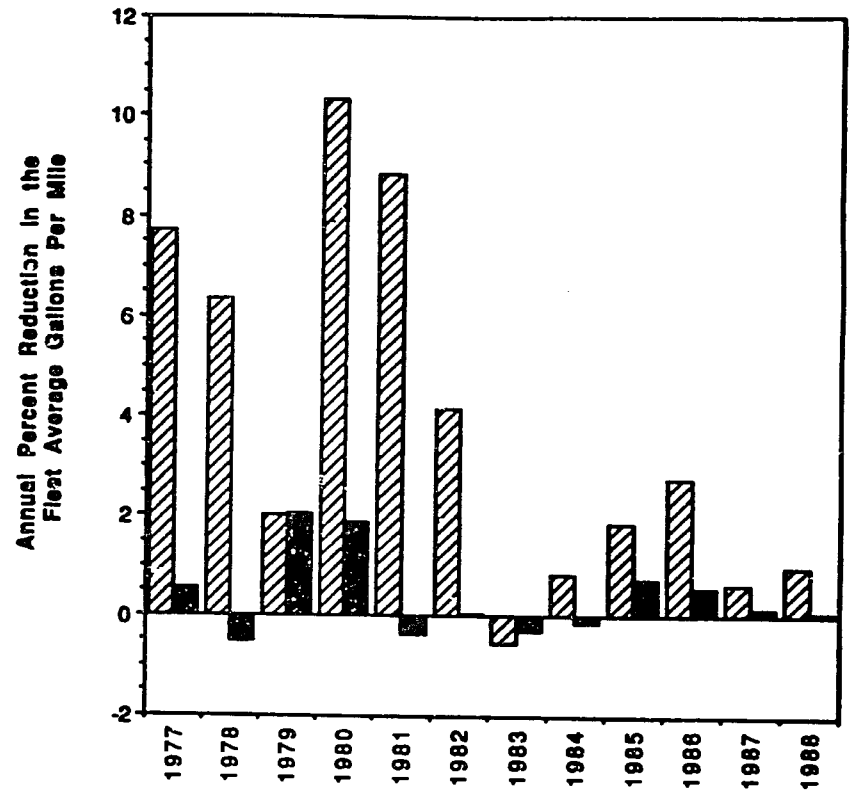


Figure 7 Divisia decomposition of the change in the sales-weighted fuel economy of all new automobiles. The decomposition is of the annual reduction in gallons per mile into the part due to fuel-economy improvement in each size class (hatched bars) and the part due to increased market shares for the smaller size classes (dark bars). Data from (20)

decade (Table 6). Weight reduction has, of course, been a major element in fuel-economy improvement.

Trade-offs among performance, emissions, cost, safety, and fuel economy have also been used by manufacturers in meeting their goals and by buyers in meeting theirs. The significant reduction in acceleration time since 1982, shown in Table 6, is such a trade-off. Cars with higher acceleration performance are attracting buyers.

To estimate the importance of the trade-off between acceleration performance and fuel economy in recent cars, several popular cars were selected and the performance data for different models of each car were studied (models with different or modified engines but the same body) to obtain a statistical relationship between fuel economy and 0–60 mph acceleration time. The relationship found is that fuel economy is roughly proportional to the square-root of acceleration time. Thus, other things being equal, the reduction in average (sales-weighted) acceleration time from 14.4 s in 1982 to 12.9 s in 1987 caused a decline in the fuel economy of new 1987 cars from a hypothetical 29.6 mpg to the actual 28.0 mpg (a 5% decline).

This analysis underestimates the fuel-economy benefit of designing vehicles with smaller engines. The fuel consumption in idling is roughly proportional to engine displacement, and idling and low-power output dominate urban driving. Through transmission management one can enable a smaller engine to provide good acceleration at low to moderate vehicle speeds, but manufacturers are designing vehicles with extraordinary acceleration capability as a marketing strategy.

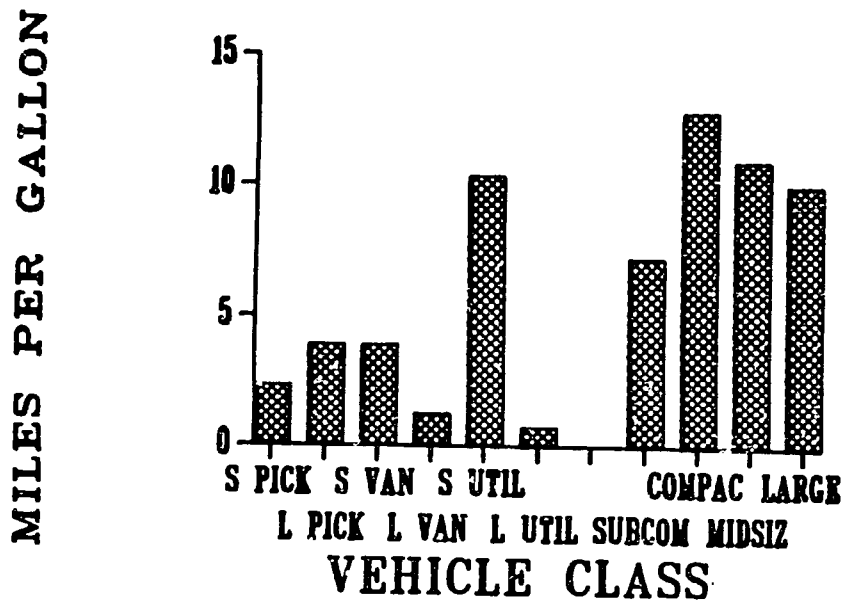


Figure 8 Change in light truck and automobile fuel economies from 1976 to 1987 by vehicle class, with six light truck classes shown at left and four automobile classes shown at right. See (2) for definitions of the classes. Source: (21)

The trade-off between fuel economy and cost in the context of contemporary vehicles cannot be reliably determined from the prices of vehicles, because typical production models with higher fuel economy are cheaper rather than more costly. There are two related reasons: (*a*) Marketing concepts dictate that high fuel economy be coupled with the stripped-down model; the customer interested in fuel economy is also believed to be interested in a low-cost vehicle. (*b*) In many current applications, technology that can improve energy-efficiency (such as weight reduction at a given size, an increased engine power-to-size ratio, and improved part-load performance with a turbocharger) is being adopted in ways that increase acceleration performance rather than fuel economy.

The In-Use Fuel Economy of the Entire Fleet

The Environmental Protection Agency determined in the early 1980s that vehicles in use achieve 10% lower fuel economy in actual urban driving than in the urban cycle test for new vehicles, and 22% lower fuel economy in actual highway driving than in the highway test (22). Regardless of age, well-maintained vehicles achieve about 15% lower fuel economy in use than the new nominal vehicle rating: New-Vehicle Composite Fuel Economy =

Table 6 Some average characteristics of new cars[a]

	volume / weight (cu. ft./ton)	power / displacement (hp/cu. in.)	acceleration 0–60 mph (seconds)	power / curb weight (hp/lb)
1987	70.4	.731	12.9	0.037
1986	70.5	.694	13.2	0.036
1985	69.8	.672	13.3	0.036
1984	69.7	.637	13.8	0.034
1983	70.1	.615	14.0	0.033
1982	69.4	.609	14.4	0.032
1981	58.9	.594	14.4	0.032
1980	67.1	.583	14.3	0.032
1979	62.6	.545	13.8	0.034
1978	60.8	.538	13.7	0.034

[a]domestic and imported, sales weighted
Source: (16)

$[.55/\text{urban} + .45/\text{highway}]^{-1}$, where urban and highway here refer to the corresponding laboratory fuel economies. This composite fuel economy is the new-vehicle fuel economy quoted throughout this report, except where specified otherwise.

It is now believed, although without solid statistical evidence, that the discrepancy between the typical new-vehicle in-use fuel economy and the nominal rating has increased to as much as 25%. Reasons for an increasing disparity are: increasing urban congestion, increasing share of urban driving, higher speeds on open highways, and higher levels of acceleration. In connection with the latter, some powerful vehicles are being described as cycle busters. Their high power enables them to be driven far outside the test cycle regimes, probably with poor fuel economy, but they incorporate features enabling them to obtain a satisfactory rating.

The other consideration in linking a history of new-vehicle fuel economies (FE_i, where i is the year) to the in-use fuel economy of the entire fleet, is the miles of travel of older vehicles. For this a simple approach is to use 1982 survey data (6). Analysis of these data yields the fraction VM_i of total vehicle-miles traveled by vehicles in each age group (i being the age of the vehicle). The in-use fuel economy of the fleet in 1987 is thus:

$$0.85 \times \left(\sum_i VM_i\right)\left(\sum_i VM_i/FE_i\right)^{-1}$$

The analysis of the connection between the nominal new-vehicle fuel economy and that of the entire US fleet shows that the in-use fuel economy of all automobiles in 1987 was about 18 mpg, far below 28.3 mpg, the 1987

nominal new-car fuel economy; 24.1 mpg, the in-use fuel economy of new cars (using a correction factor of 0.85); or 22.0 mpg, the in-use fuel economy of new light-duty vehicles (16, 17). The rapid advances in new-vehicle fuel economy made in the late 1970s and early 1980s are still working their way through the system. Many old low-fuel-economy vehicles are still being driven.

Let us turn from this record of past progress to consider the possibilities for further increases in fuel economy.

TECHNOLOGY FOR FURTHER FUEL-ECONOMY IMPROVEMENT

There are many options for improving fuel economy. Moreover, many of the options are alternatives to each other. There is not a single path to high fuel economy at this time. In addition, some technologies for improving fuel economy can also reduce emissions. Others can increase them. Many of the technologies also provide performance benefits. The potential for combined benefits has become critically important.

The energy-efficiency of vehicles can be improved in many ways, because energy uses and losses occur in many ways (Figure 9). Energy use can be analyzed in terms of *the energy loads* that arise in operating the vehicle, i.e. what the drive wheels must accomplish, and *the efficiency of the engine-transmission system*, which converts fuel and provides energy to the drive wheels as it is needed. The term efficiency can be applied to the engine and transmission, given the load, but not to the loads.

The lower half of Figure 9 shows that air resistance, tire resistance, and braking loads are comparable in urban driving. In high-speed driving, air resistance dominates. The upper half of Figure 9 shows that only about 12% of the fuel energy in the tank reaches the drive wheels. There are many losses. One of them is not usually acknowledged in discussions of this kind: According to fundamental principles, the process of combustion in itself decreases the quantity of work that can be obtained from fuel energy by about 30% (23). This is due to the irreversibility of combustion, the degradation of energy, reducing its availability to do work. Perhaps this surprising result will seem more reasonable if one considers the extreme case of low-temperature combustion; in low-temperature combustion very little work (such as rotational energy) could be extracted from all the heat generated. If instead of burning the fuel, the fuel energy were converted into electricity, in a fuel cell, this loss of available work could be avoided in principle.

The Efficiency of the Engine-Transmission System

Although the fuel economy and power-to-weight ratios of engines have been much improved in the past 15 years, much more can and is being achieved.

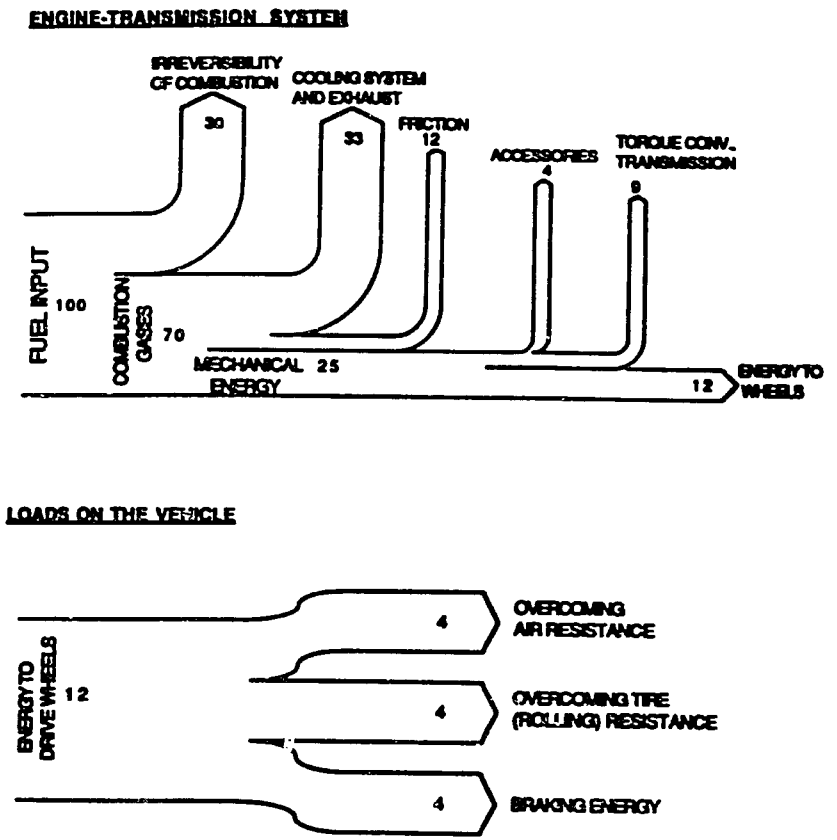


Figure 9 Flows of available energy in operating a typical car in the federal test procedure (urban driving cycle). Available energy is the capacity of the energy in question to do work. Source: (23, 24)

In today's engines about half or more of the calculated power output of the corresponding idealized engine is lost because of cycle losses, friction, and pumping losses (24). Cycle losses are due to heat loss, to the finite time for combustion, and to the finite times for filling and exhausting the chamber. These losses distort the ideal thermodynamic cycle. With the advent of powerful microprocessors and sensors, it is becoming possible to optimize the timing of the spark and the air-to-fuel ratio to reduce these losses. Electronic controls of the current generation typically respond to measurement of state variables like average air intake, temperature, and engine speed and send out signals for modifying the air-to-fuel ratio and spark timing based on encoded tables describing how a typical engine should operate. A new generation of controls involves feedback. Control is based on the sensing of state variables plus output characteristics like exhaust composition, the timing of peak

pressure in each cylinder, irregularities in speed, and knock (25). The feedback capability enables optimization of performance even if sensors or actuators have drifted in calibration, and even if the particular engine differs from the standard. Early versions of such closed-loop controls are now being installed in some production models (26).

The pumping loss is the energy to pull the air-fuel mixture into the cylinder and push out the exhaust. Unless a vehicle is being accelerated rapidly, relatively little power compared to the engine's capacity is needed (27). When power requirements are low, unless gears are shifted so the engine speed can be reduced, less cylinder pressure needs to be generated with each power stroke. This is achieved by burning less fuel. But, for the typical spark-ignition engine the air-to-fuel ratio must be kept within narrow bounds for proper combustion, so less fuel means that less air can be admitted. This is achieved by restricting the air [illegible], i.e. by throttling. At full load, i.e. with wide-open throttle, pumping losses are relatively small. At moderate load, such as steady highway driving, they are 30% to 40% as large as the engine power output (24).

There are a multitude of proposals and prototypes for reducing throttling losses. One approach is to manage gear ratios so that when the engine delivers low power then its speed is low, so it operates as near wide-open throttle as possible. Such transmission management could be achieved with continuously variable transmissions, for example. A similar result can be achieved by not fueling and firing some of the cylinders at low load. Another possibility is to use a smaller engine, that in normal operation delivers relatively little power, but that can, by delivering the charge under pressure (e.g. through supercharging), provide a lot of power. Such an engine is optimized for typical rather than maximum power requirements. Yet another option is variable control of the intake valves such that at low load the air intake occurs for only a suitable fraction of the intake stroke (28). Throttling is thus largely avoided.

The type of engine that has been in use for many decades is already highly refined and so is more difficult to improve than those in a low state of development. While significant improvements in controls, friction reduction, and part-load strategy are still possible with the typical gasoline engine, really large improvements may require substantial departures. Paradoxically, however, any radical departures will have to compete with the highly developed engines we already have—implying that a great deal of careful development will be needed before any substantially different engine could become competitive.

Among the alternative engine concepts is the direct-injection diesel, in use in some production models and prototypes in Europe. In R&D is the more radical ceramic-coated diesel, with some ceramic parts, which would be

operated at much higher temperatures, with the extra energy in the exhaust gas captured to achieve high efficiency.

An exciting spark-ignition engine initiative is the lean-burn (high air-to-fuel ratio) two-stroke engine. The two-stroke is currently used in small engines, such as for lawn mowers, and in many marine applications. As noted above, the power output of standard automobile engines has been increased in the last decade for a given displacement, while emissions have been sharply reduced. These benefits have been achieved through many refinements and complications, as anyone over 30 knows who looks under the hood. Such refinements have not yet been incorporated in the two-stroke engine.

The two-stroke engine has twice as many power strokes in a given number of revolutions as the four-stroke and in its basic version has no valves, only ports, which are uncovered as the piston moves. A three-cylinder engine could have almost the same output as a six-cylinder four-stroke engine (of twice the displacement). Saab used such an engine (in unmodernized form) in the 1960s, and cars with them are manufactured in East Germany. This two-stroke engine would be light enough to be carried by a strong person; and it would be relatively cheap and easy to maintain.

But would it be possible to achieve low emissions and high fuel economy by refining the two-stroke engine? Development work is now under way by engine manufacturers around the world. Extraordinary improvements in the fuel economy, emissions, and misfire performance have already been achieved, compared to two-stroke engines of the past, with modern fuel injection systems (29–31). It is not clear where this development work will lead. For application as a small automotive engine, will supercharging be essential? What level of catalytic clean up of the exhaust will be necessary? How simple, light, and cheap will the resulting engine be?

Fuel-Economy Emissions Interactions

In the context of 1988 markets and political climate, the most important possibility for much higher fuel economy may be technology that couples fuel economy with emissions reductions. Many people have the misconception that emissions reduction and fuel economy are antithetical, because, given a vehicle design, if you would reduce emissions you must add equipment or make adjustments that will decrease fuel economy. In designing a new vehicle, the opposite relationship can occur. New technology or fundamental redesign often offer opportunities to both improve energy-efficiency and reduce emissions.

A major fuel-economy tie to emissions reduction arises from the nature of the mass regulatory-standards for emissions, i.e. the limits on grams of emissions per mile (32). A vehicle that consumes relatively little fuel per mile has an easier-to-meet standard in percentage terms (concentration of pollut-

ants in the combustion gases). Emissions decrease less than a simple proportion of fuel use would suggest, however, with, e.g. a smaller engine.

In addition, some fundamental approaches to fuel-economy improvement also enable percentage emissions reductions. As an example, consider a lean-burn engine. With lean-burn, the combustion temperature is lower, reducing NO_x formation, as shown in Figure 10. The fuel-efficiency is nevertheless improved, because air is a better thermodynamic medium than (evaporated) gasoline. The increase in unburnt hydrocarbon with air-to-fuel ratio, which begins at the right of Figure 10, is a major challenge. It can be prevented, in principle, by improving ignition, e.g. through a higher-energ ignition mechanism, and it can be mitigated by improved exhaust after treatment.

It is possible that a lean-burn engine can be developed with relatively lov emissions, with little or no after-treatment, e.g. without a catalytic converter

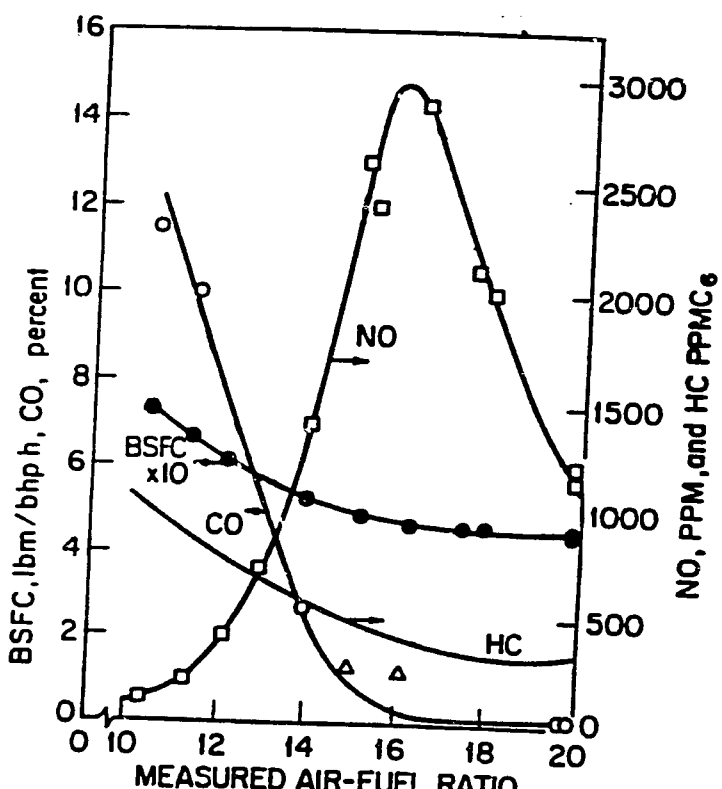


Figure 10 Exhaust gas composition and specific fuel consumption of a sample automotive engine, vs air-to-fuel ratio. The stoichiometric ratio is 14.6. Courtesy of Donald J. Patterson.

In a very high fuel-economy vehicle, such a system might be able to meet strict emissions standards. One disadvantage of this approach is that there is no practical after-treatment to reduce NO_x in an oxygen-rich environment, so that the control of NO_x would have to be achieved entirely in the engine.

Reduction of the Vehicle Load

The load has three components: energy that goes into braking, air resistance, and the tire, or rolling, resistance. A general approach to reducing braking and rolling resistance is weight reduction. Improvements in design and increasing use of lighter and stronger materials (plastics, composites, high-strength steels, and aluminum) are continuing. To recover energy that would otherwise go to the brakes requires an energy storage scheme, such as braking through a motor-generator that charges batteries, or braking by transferring energy to a flywheel. At present, these appear to be costly options for a small vehicle. Dramatic reductions of air drag are now going on as designers learn how to create the appropriate smooth surfaces and integrate them into the vehicle (26). Where the average coefficient of aerodynamic drag of 1979 model US cars was 0.48, the Taurus/Sable has a drag coefficient of 0.30 and prototype vehicles have coefficients of less than 0.2. Rolling resistance was sharply reduced with the introduction of radial tires. Further improvements are in development (26), but are limited by the primary need for tires to hold the road.

In this brief summary, many important measures that could be (or already are being) used to improve fuel economy have not been discussed, or have been mentioned only in passing. The point is that there is an extraordinary ferment in automotive technology at this time. It is due to the conjunction of new capabilities in materials, information, and control, which affect design and manufacturing as well as the vehicle itself. What will be the impact on fuel economy? Let us briefly examine the influence of the marketplace.

ECONOMICS AND FUEL ECONOMY

Through improved design and technological innovation, the loads on a vehicle can be reduced and the energy-efficiency of the propulsion system increased without necessary detriment to vehicle size, performance (e.g. acceleration), safety, and emissions. In addition, trade-offs can be made among fuel economy, size, acceleration performance, cost, safety, and other characteristics. In today's market conditions, two kinds of change in the fuel economies of new vehicles can be expected: (*a*) modifications to existing or planned production models and (*b*) creation of substantially different vehicles.

Modifications to Current Models

Technologies to improve fuel economy, which are already developed or whose development is of low risk, and were, in 1985, considered likely to be incorporated by domestic automobile manufacturers into existing and planned models, are the basis for a cost estimate by Energy and Environmental Analysis, Inc. (33). As shown in Table 7, a $48 per vehicle price increase is typical for each one mpg improvement in the fuel economy of a current compact car. The modifications considered are listed in Table 8. The corresponding cost of saving gasoline, starting with today's typical new vehicle, is less than 50 cents per gallon saved—decidedly less than the price of gasoline. (A 10% real discount rate, a vehicle lifetime of 10 years, and an average of 11,600 miles per year of driving are assumed.)

Appropriate combinations of the cost-effective technologies considered in Tables 7 and 8 are capable of changing the current compact cars, with fuel economy of about 30 mpg, into cars with fuel economy in the mid-40s or higher.

These costs are based on estimates of the manufacturing costs (materials and labor) multiplied by the average long-term ratio of vehicle retail price to manufacturing cost. This ratio is four to five. It accounts for all other costs: R&D, plant and equipment, tooling, administration, and all distribution and sales costs, as well as earnings.

The reader has to be careful in interpreting these numbers. As discussed above, the price of typical vehicles declines with increasing fuel economy, because in a high-fuel-economy model the engine system is simpler than one

Table 7 The cost of near-term technology to improve automotive fuel economy[a]

Typical fuel economy for application (mpg)[b]	Retail price increase per vehicle for one mpg improvement in fuel economy (1986 $)	Total cost per gallon saved[c] ($/gal.)
30	48	$0.46
40	46	$0.77
50	37	$0.98

[a] Adapted from Energy and Environmental Analysis, Inc., "Analysis of the Capabilities of Domestic Auto Manufacturers to Improve Corporate Average Fuel Economy," Appendix A (compact cars), Ref. 32.

[b] The 30, 40, and 50 mpg descriptions are nominal; they correspond to technologies listed by EEA as being incorporated in 1986–1988, 1989–1991, and 1992–1995, respectively. See Table 8.

[c] Value of the incremental retail price of the vehicle at the time of gasoline saving, per gallon. For application at 30 mpg, the cost is $0.85 \times 48 \times 1.4/[((1/30) - (1/31)) \times 116{,}000]$, where 85% is the in-use fuel economy compared to nominal, 1.4 is the appreciation of the incremental cost of the vehicle using a 10% real discount rate, and 116,000 the expected mileage in the first 10 years of automobile life.

Table 8 Sample technologies considered in the cost estimate[a]

	Increased fuel economy (percent)
Technologies introduced 1986	
weight reduction at constant size (materials substitution)	7
rolling resistance reduction (improved tires)	4
reduced aerodynamic drag	3
engine-efficiency improvement	
friction reduction (especially piston and rings)	4
improved lubricants	2
multi-point fuel injection	7
new engine designs—fast-burn cylinder	4
four valves per cylinder	8
roller cam followers (reduced friction in moving valves)	3
accessory efficiency improvement	2
front wheel drive	12
Technologies introduced 1989–1991	
optimization of transmission	
electronic transmission control	3
automatic overdrive	8
Technologies introduced 1992–1995	
engine-efficiency improvement	
diesel	45
intake valve control (variable valve timing)	8
optimization of transmission	
continuously variable transmission	12

[a] Some technologies, although briefly named, represent a complex of design changes. The timing for introduction of technologies in specific models is that forecast by Energy and Environmental Analysis. This is not a complete listing. Moreover, some technologies can be improved with time. On the other hand, some are mutually exclusive, have limited applicability, or have already been partially applied. One cannot simply combine the percent improvements. See the original references for many of the details.
Source: (32, 33)

souped up for high acceleration performance and the design is less luxurious. In contrast, incremental costs are shown in Table 7, the average cost of modifying given vehicle models to increase their fuel economies. Typically these improvements do not require loss of acceleration-performance or reduction of interior volume, although there is weight reduction. (Some loss of acceleration performance would, however, probably characterize diesel engines, if adopted.)

Finally, and of great importance, the incremental cost of these technologies, as calculated here, does not mean that the preferred fuel-economy technologies will ultimately cost as much. Fuel-economy technologies have been costed here as add-ons, additional parts, and fabrication steps in the manufacture of existing automobile models. When the technologies are

integrated into the design and manufacture of new vehicles, it is likely that the incremental cost of the fuel-economy benefits will be much less.

Altogether New Vehicles

The highest-fuel-economy vehicles already in production have impressively high mpg ratings, but tend to be rather small vehicles with low acceleration performance. Some more ambitious prototype vehicles are shown in Table 9. Many incorporate radical innovations, such as aluminum bodies and engines (GM), direct-injection diesels that stop when the vehicle coasts or stops, and start as needed (VW & Renault), and direct-injection diesels with continuously variable transmissions (Toyota). Extensive use of plastics and light metals characterizes all these prototypes. The potential improvement suggested by prototypes is difficult to evaluate because they are often single-purpose projects. A practical, marketable vehicle may involve many compromises. The cost and performance that cars like these would have if designed for the market and mass produced remain to be determined. There is, however, every expectation that cars with very high fuel economy and good space and performance characteristics can be built, perhaps without a substantial cost penalty beyond the manufacturer's initial tooling investment (27, 35).

Table 9 High-fuel-economy prototype vehicles[a]

	Curb weight (lbs.)	Power / curb wt. (hp/lb.)	Fuel economy[b] (mpg)	Prototype status
2–4-passenger				
GM TPC	1040	0.037	66	complete
Volvo LCP 2000 diesel	1555	0.033	70	complete
Renault Vesta	1047	0.026	89	complete
4-passenger				
Volkswagen E80 diesel	1540	0.033	83	development
Peugeot ECO 2000	990	0.028	79	development
4–5-passenger				
Volkswagen Auto 2000 diesel	1716	0.031	66	complete
Renault EVE+ diesel	1880	0.027	70	complete
Peugeot VERA+ diesel	1740	0.029	66	development
Toyota AXV diesel	1430-target	0.039	97	development

[a] Ref. 26
[b] For gasoline vehicles measured with a standard test, adjusted as per Ref. 22. For diesel vehicles, unadjusted.

The Market and Fuel-Economy Improvements

How likely is the implementation of major fuel-economy increases in the next decade or so? There is technological momentum for incorporating some of the modifications listed in Table 8, at the typical costs shown in Table 7. On the basis of the cost advantages to consumers, Energy and Environmental Analysis projected in 1985 that many of these improvements will be made by domestic manufacturers by 1995. But with today's fuel prices and fuel-price expectations, these projections appear overoptimistic.

Two principal reasons for lack of urgency on the parts of manufacturers and car buyers are evident from the "von Hippel-Levi effect," Figure 11: (*a*) The contribution of fuel purchases to the cost of driving is, at present, relatively small—it is less than the cost of insurance. (*b*) The curve representing total cost vs fuel economy varies only slowly with fuel economy; the vehicle buyer can be expected to be indifferent over a broad range of fuel economy (36). For example, if a person drives 12,000 miles per year and his/her car is improved from 30 to 40 mpg (nominal), then 120 gallons of fuel are saved annually. If the cost of saved energy is 60 cents per gallon (between 46 and 77 cents, Table 7) and the cost of fuel is $1.00 per gallon, the net value of the saving is about $50 per year, a small motivation. Moreover, the simple payback on the increased price of the vehicle is about four years, somewhat long in terms of consumer behavior. (The annual operating savings are 120 gallons or $120, while the increase in the up-front cost is, from Table 7, about $470.) In other words, while the nation may have a great interest in reducing total petroleum use and some geographical regions may be very concerned with reducing fuel use by vehicles in order to reduce air pollution, the individual has very little interest, in simple economic terms, in the fuel economy of the vehicle he or she buys.

Without a stimulus other than fuel saving, the manufacturer would be even less inclined to make high-fuel-economy vehicles than the consumer to buy them in today's market. A manufacturer would incur a significant technological risk and substantial opportunity costs in introducing new fuel-efficient technology. He is very unlikely to do this if his prospective buyer is likely to be indifferent about the new product.

Events, however, could alter this pattern of inertia. There are three important kinds of possible events: (*a*) new technology with multiple benefits, one of which is fuel economy, (*b*) much higher fuel prices and/or fuel shortages, or (*c*) strengthened fuel-economy regulations or other changes in public policy with strong fuel-economy implications.

Technology with multiple benefits may become part of the program of manufacturers for whom innovation is a major competitive strategy. Consider one fuel-economy innovation, the continuously variable transmission. The

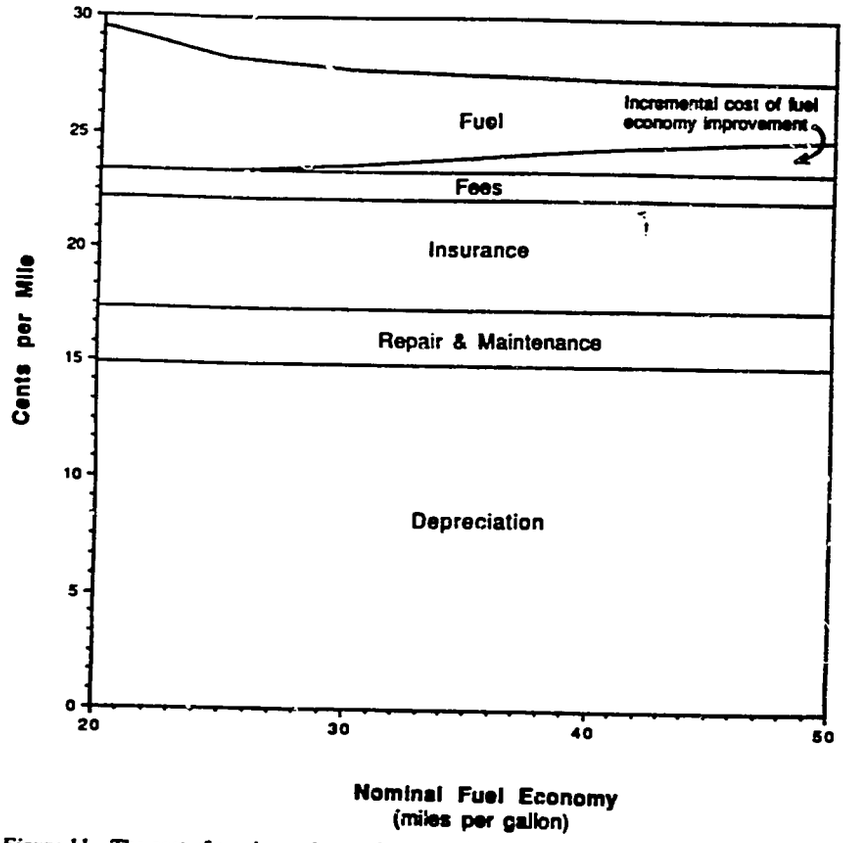


Figure 11 The cost of owning and operating a midsize car vs fuel economy. The data at left are for 1988 midsize cars (where average in-use fuel economy is 23 mpg) from the American Automobile Association (6). The incremental cost is taken from Table 7. The depiction of several costs as independent of the fuel economy of modified vehicles is somewhat arbitrary. Some argue that costs will fall, e.g. that lighter plastic components will be more durable and thus decrease depreciation; others argue that costs will rise, e.g. that the vehicle will require more maintenance because it is more finely tuned.

driver gets a different feel during acceleration. Such a technology could establish new standards of performance, creating demand for cars that also have high fuel economy.

A different kind of technical change would be creation and wide adoption of a narrow two-passenger vehicle as an extra vehicle for use in commuting and errands. A relatively safe, high-performance vehicle could probably be manufactured. Two factors make wide adoption of such a vehicle conceivable: (*a*) Rising incomes in many households and rapidly increasing vehicle

life are encouraging purchase of "excess" vehicles, often special-purpose vehicles. In 1983, 13% of all vehicles were already in excess of the number of drivers in the household (15). (*b*) A small high-performance vehicle, if afforded special parking privileges, might have appeal. There is a tremendous fashion for pickup trucks as passenger vehicles; and many of these are two-passenger vehicles. Of course, even though a very small two-passenger vehicle might have a social rationale, it might not appeal to buyers.

Fuel price increases would also motivate fuel-economy increases, but the effect is not thought to be strong (37, 38). It has been estimated that the price elasticity is −0.5 for the fuel economy of new car purchases. That is, for every 10% increase in fuel price, the average buyer would opt for a vehicle with 5% higher fuel economy. But this analysis probably overestimates the impact fuel price increases would have in the United States, because the present level of fuel economy is primarily due to the regulatory standards. A major increase in fuel economy would require fuel price increases of a factor of two or more, fuel shortages, or major changes in public policy.

PUBLIC POLICY AND FUEL ECONOMY

A Review of Recent Initiatives

Before addressing future policies that could lead to major fuel-economy improvements, the policy experience gained in the past dozen years is briefly reviewed.

INFORMATION The federal government systematically determines the fuel economy of each vehicle model every year, publishes the information in the Gas Mileage Guide, and has a window sticker put on each new vehicle. Although the in-use fuel economy varies considerably among individual vehicles of the same model (as maintained and driven), this information is reliable enough for buyers and has removed the extensive confusion that characterized fuel economy before the age of a standardized laboratory test.

PERFORMANCE REGULATIONS The mandated improvement of corporate average fuel economy (CAFE) was probably largely responsible for the approximate doubling of the new car fuel economy from 1974 to 1986, although some argue that fuel price increases alone would have driven a similar increase. The history of the sales-weighted fuel economy of new cars, when compared with the history of CAFE regulations and the price of gasoline (Figure 12), leaves little doubt as to the engine that drove the improvements. In examining the figure, note that the 1970 gasoline price was a little higher than that in 1973, that the CAFE standards were legislated in 1975, calling for an increase to 27.5 mpg by 1985, and that fuel price

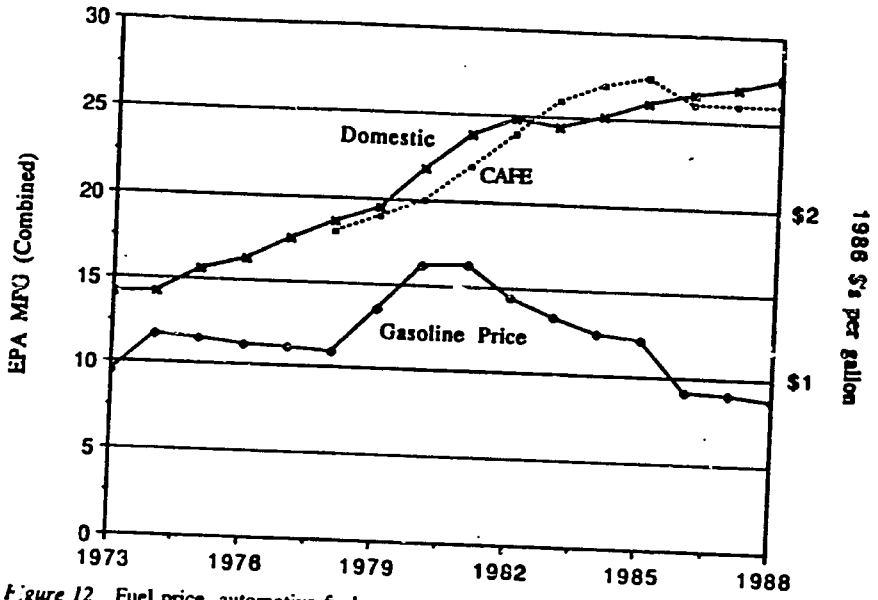


Figure 12 Fuel price, automotive fuel economy, and the CAFE standards 1973–1988. In the period before 1973 the real fuel price declined gradually. Source: (39)

elasticity studies suggest an elasticity substantially less than one, rather than greater than one.

No further increases in fuel economy are mandated, although the 27.5 mpg standard for cars remains. The 27.5 mpg standard has not yet been fully imposed, however, reductions being granted on petitions from Ford and General Motors. There are also standards for trucks, but these are not set by the legislation as such; they have been set largely in conformity with manufacturers' wishes.

Of the arguments now offered against further increases in the CAFE standards, one is especially powerful: that CAFE standards discriminate against corporations offering a full line of vehicles (including large ones). Modifications that have been suggested are: mandating a percentage improvement for each corporation and mandating a certain improvement for size-weighted fuel economy (40).

THE GAS-GUZZLER TAX The average fuel economy of vehicles purchased can be improved by a carrot or stick at the time of purchase. The gas-guzzler tax has this purpose. It kicks in at $500 for cars with fuel economy below 22.5 mpg and grows to more than $3000 for a fuel economy below 12.5 mpg. In 1986 the US Treasury collected $148 million, as the program came into its final form.

FUEL TAXES In the United States, motor fuel taxes average 23 cents per gallon and have little impact on which vehicles are purchased and relatively little impact on how much vehicles are driven. Modestly higher fuel taxes might influence owners of inefficient cars to trade them in earlier. Unfortunately, this process might not hasten the time when inefficent cars were scrapped. What would be likely to happen is what happened in the late 1970s: The prices of used cars with low fuel economy were depressed so they were bought and used by people for whom the low first cost was a strong attraction.

Fuel taxes in the United States have not been conceived as influencing purchases of light-duty vehicles. In many other countries, however, gasoline taxes are several times higher than the 23 cents per gallon average here (41). The $2 to $4 per gallon price of fuel in Europe does have a major impact on vehicle purchases and use. A definitive study of the European experience, however, would also have to take into account the much higher population density and geographical structure, which discourages the long-distance commuting by personal vehicles that is common in the United States.

RESEARCH AND DEMONSTRATION The Department of Energy has an ongoing R & D program in Transportation Energy Conservation. The 1987 appropriation was $56 million. The program is limited to work on radical propulsion systems, especially ceramic diesels, gas turbines, and electric vehicles, and in advanced materials, especially for engines. There is a general sense about this program that, although important transportation product goals, such as an electric vehicle, have not been achieved, some basic yet practical work has been done, especially on ceramics and batteries, which may have considerable economic value. The existing program is much smaller than the Cooperative Automotive Research Program, an R & D program including substantial basic research, proposed during the Carter administration, but not implemented.

The Rationale for Public Policies to Increase Fuel Economies

Concerns for national security relative to petroleum supply and for the well-being of the economy in the face of increasing energy prices, have justified public policies aimed at energy-efficiency. Concerns for metropolitan air quality, and to a lesser extent regional air quality, have justified the emissions standards.

The petroleum-supply issues remain important in spite of the current low price because of our rapidly increasing dependence on imports (caused by the low price). Net imports of petroleum are rising toward 40% of consumption, a higher level than that of 1973, before the first oil shock, and close to the 45% level of 1978, before the second oil shock.

Air quality concerns are increasing because (*a*) metropolitan air quality

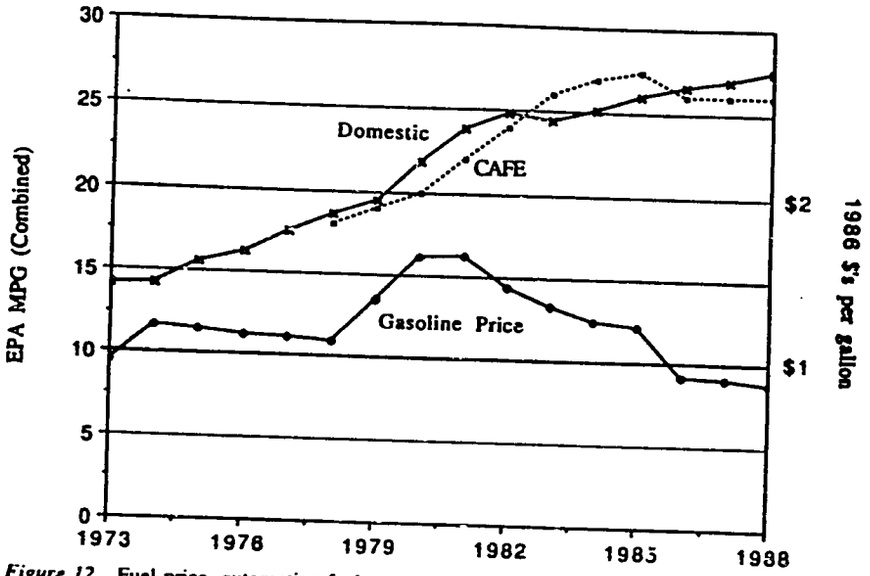


Figure 12 Fuel price, automotive fuel economy, and the CAFE standards 1973–1988. In the period before 1973 the real fuel price declined gradually. Source: (39)

elasticity studies suggest an elasticity substantially less than one, rather than greater than one.

No further increases in fuel economy are mandated, although the 27.5 mpg standard for cars remains. The 27.5 mpg standard has not yet been fully imposed, however, reductions being granted on petitions from Ford and General Motors. There are also standards for trucks, but these are not set by the legislation as such; they have been set largely in conformity with manufacturers' wishes.

Of the arguments now offered against further increases in the CAFE standards, one is especially powerful: that CAFE standards discriminate against corporations offering a full line of vehicles (including large ones). Modifications that have been suggested are: mandating a percentage improvement for each corporation and mandating a certain improvement for size-weighted fuel economy (40).

THE GAS-GUZZLER TAX The average fuel economy of vehicles purchased can be improved by a carrot or stick at the time of purchase. The gas-guzzler tax has this purpose. It kicks in at $500 for cars with fuel economy below 22.5 mpg and grows to more than $3000 for a fuel economy below 12.5 mpg. In 1986 the US Treasury collected $148 million, as the program came into its final form.

FUEL TAXES In the United States, motor fuel taxes average 23 cents per gallon and have little impact on which vehicles are purchased and relatively little impact on how much vehicles are driven. Modestly higher fuel taxes might influence owners of inefficient cars to trade them in earlier. Unfortunately, this process might not hasten the time when inefficent cars were scrapped. What would be likely to happen is what happened in the late 1970s: The prices of used cars with low fuel economy were depressed so they were bought and used by people for whom the low first cost was a strong attraction.

Fuel taxes in the United States have not been conceived as influencing purchases of light-duty vehicles. In many other countries, however, gasoline taxes are several times higher than the 23 cents per gallon average here (41). The $2 to $4 per gallon price of fuel in Europe does have a major impact on vehicle purchases and use. A definitive study of the European experience, however, would also have to take into account the much higher population density and geographical structure, which discourages the long-distance commuting by personal vehicles that is common in the United States.

RESEARCH AND DEMONSTRATION The Department of Energy has an ongoing R & D program in Transportation Energy Conservation. The 1987 appropriation was $56 million. The program is limited to work on radical propulsion systems, especially ceramic diesels, gas turbines, and electric vehicles, and in advanced materials, especially for engines. There is a general sense about this program that, although important transportation product goals, such as an electric vehicle, have not been achieved, some basic yet practical work has been done, especially on ceramics and batteries, which may have considerable economic value. The existing program is much smaller than the Cooperative Automotive Research Program, an R & D program including substantial basic research, proposed during the Carter administration, but not implemented.

The Rationale for Public Policies to Increase Fuel Economies

Concerns for national security relative to petroleum supply and for the well-being of the economy in the face of increasing energy prices, have justified public policies aimed at energy-efficiency. Concerns for metropolitan air quality, and to a lesser extent regional air quality, have justified the emissions standards.

The petroleum-supply issues remain important in spite of the current low price because of our rapidly increasing dependence on imports (caused by the low price). Net imports of petroleum are rising toward 40% of consumption, a higher level than that of 1973, before the first oil shock, and close to the 45% level of 1978, before the second oil shock.

Air quality concerns are increasing because (*a*) metropolitan air quality

continues to be unsatisfactory in many areas, and the public is clearly interested in making progress; (*b*) regional air quality impacts, especially acidification of lakes and forest death, are increasingly troubling; and (*c*) the greenhouse effect will affect the global climate, as a result of increasing atmospheric concentrations of infrared-absorbing gases, such as carbon dioxide, NO_x, methane, and chlorofluorocarbons. The production of carbon dioxide by gasoline-fueled vehicles is inversely proportional to their fuel economy. The joining of these strengthened environmental concerns with those for petroleum supply gives impetus to consideration of stronger fuel economy and emissions policies.

Major Policy Options for the Near Future

INDUCED MOTOR-FUEL PRICE INCREASE Other industrial countries impose high motor fuel taxes with the result that fuel economy is of economic importance to the vehicle purchaser. In the second quarter of 1988, taxes constituted 31% of the price of gasoline in the United States, but 47% in Japan and 63 to 79% in the major countries of Western Europe (41). The higher fuel prices in Japan and Europe may be responsible for the relatively rapid introductions there of fuel-economy innovations.

Under US conditions, a motor fuel tax that might generate a great deal of fuel-economy innovation, on the scale of $2.00 per gallon, is not feasible in the foreseeable future. The strong dependence of rural areas on cars and light trucks, and the importance of commercial trucking in our economy, suggest that it would be inappropriate to approach fuel-economy improvement primarily through use of a stick that strongly penalizes those who drive a great deal.

A moderate fuel price increase might, however, be a part of a effective package of policies aimed at improved fuel economy. (At this time it seems we could have a moderate motor fuel tax increase for revenue purposes.) Such a package could emphasize technology policies and strengthened standards for new-vehicle fuel economies, but include induced fuel price increases of 25 to 50 cents to provide a balance of motivations. The concept is that the entire cast of players (manufacturers, vehicle buyers, drivers, and those responsible for other components of the system), will be able to respond more effectively if all are motivated. In contrast, if, for example, manufacturers are pressured to bring out higher-fuel-economy vehicles but buyers are wholly indifferent, there would be a dissonance, which might lead people to look for loopholes instead of increased fuel economy.

STRENGTHENED FUEL ECONOMY REGULATIONS The tool of minimum standards for the fuel economy of new vehicles, standards that are periodically strengthened, has worked and would probably work in the future

(especially if used in concert with other policies). Properly designed, it would put all manufacturers on an essentially equal competitive footing. As discussed above, there is good evidence that the overall cost of improvements would be more than matched by savings on fuel, in the fuel-economy range that is likely to be considered and over a time period that allows manufacturers to retool and change models at a typical pace.

A critical component in strengthened standards would be closure of the light-truck loophole. Light-truck performance standards would have to be developed and written into the legislation, instead of being left to the discretion of an agency.

The second half of the 1980s is, however, a time of low oil prices. Under these conditions the political will to adopt a controversial policy of strengthened fuel-economy regulations will probably be lacking. And yet it would be a straightforward, economic, and equitable way to push petroleum-supply problems off into the distant future.

STRENGTHENED AIR POLLUTION STANDARDS Local and regional air pollution problems remain serious a quarter century after the first Clean Air Act (1963). Progress has been made in cleaning up particular sources. For example, measurements of light-duty vehicles in use by the Environmental Protection Agency show that emissions per vehicle have been greatly reduced. The typical model 1988 car in normal use emits roughly one fifth of the hydrocarbons and carbon monoxide and one-third of the NO_x that an early 1970s car emitted per mile (42). Extraordinary progress has been made through the combined efforts of government and the manufacturers. In typical use our light-duty vehicles are very clean.

On the other hand, vehicle-miles traveled have increased about 80% since 1970. In addition, the standards are not completely definitive because nonstandard situations may create most of the pollution. EPA is conducting more careful studies of (*a*) emissions, especially evaporation of fuel rather than tail pipe emissions, in very hot and sunny weather, (*b*) emissions, especially carbon monoxide, in very cold weather, (*c*) emissions in high-power (wide-open throttle) operations, (*d*) emissions in heavy congestion situations, and (*e*) emissions from vehicles whose emissions control systems have failed. (For the last group inspection and maintenance programs have been introduced in regions not meeting air quality standards. Such programs can work, but are difficult to implement so as to detect and correct most of the gross emitters.)

To develop and exploit the technological opportunities to further reduce vehicle emissions, it would be valuable to strengthen technology policies (such as R&D programs) as well as to enact still more effective air pollution standards. In designing more effective standards more attention to (*a*) fuel

economy–emissions interactions and (*b*) nonstandard situations seems called for. It may be that a regulatory focus on further tightening of the grams per mile limitations is not the most effective way to improve air quality. For example, taxes and rebates based on emissions performance might be more effective.

RESEARCH The body of new ideas, systematic knowledge, trained personnel, and instrumentation associated with research activity is the context in which invention and development take place. The strength of the United States in basic science research has persuaded many that our arrangements for research are in good shape, but that is not accurate. As suggested by the recent spate of engineering activity at the National Science Foundation, research in basic engineering or basic technology is very uneven in the United States. The tendency of the private sector to underinvest in research (compared to development) is well established. One of the large holes is research relating to technologies for land vehicles and their manufacture. For example, only recently has research relating to basic properties of combustion begun to be at all adequate. Many issues relating to engines and transmission management need thorough and fundamental examination. In vehicle manufacturing, the forming of metals, plastics, and ceramics is still largely an art rather than a science. It is not enough for manufacturers to apply the new information technology in a general manner; research on problems specific to vehicle design and manufacture must be carried out.

DEVELOPMENT AND DEMONSTRATION The stages of technical change that precede innovation are invention, development, and prototype demonstration. The context for development activity in the United States would be quite different than it is today if there were more active innovation in vehicles.

The federal government should be cautious (in the author's view) about directly supporting development and demonstration of commercial products. The nation has had bad experience with programs like the breeder reactor, synfuels, the electric vehicle, the Transbus, and Operation Breakthrough (manufactured housing). In these cases the project goals and management were far too inflexible for the creation of a commercial product. At present another major demonstration program is under way: clean coal technology. The jury is out in that case.

The pattern is not all one of failure, however. For example, major successes were achieved with partial federal support for demonstration of lighting and window technologies (43). The experience tentatively suggests two criteria for partially federally supported development and demonstration programs: (*a*) Federal participation in development and demonstration is more likely to be effective if the technology in question is small (with a low cost per

installation) so that different attempts can be made and some failures are expected from the start. (*b*) Federal participation is more likely to be effective if the technology is generic, i.e. may have a variety of applications.

INNOVATION These days the United States is known for its prowess in basic science research, while Japan is famous for taking research concepts and applying them. The first concern of technology policy must be the vitality of the private sector in adoption of new technology. The technology pull of manufacturers who want or need to innovate is required as well as the technology push of research.

While innovation in motor vehicles is needed, the nation's manufacturers are all large and cautious. The industry has matured to the point that there are no small vehicle manufacturers left. (And the barriers against a new firm entering the business, except from a foreign base, are very high.) Until the threat of innovative Japanese manufacturers became intense, the industry was largely not competing with respect to product or manufacturing innovation (44).

One reason for the manufacturers to be cautious about new technology is the scale of risks that are involved. A typical production line produces 200,000 vehicles per year. Engine lines involve more of a commitment. The tooling costs are large. The manufacturer needs to feel confident that the new product will be successful.

A second reason for caution is that US manufacturers have made several major innovations in the past couple of decades, but have been badly stung several times by poor technological performance. The Japanese may be better at innovating and avoiding the flawed product than we are. As a result they more frequently use innovation as a competitive strategy.

In the face of this problem, a policy to directly encourage innovation is called for. One possibility is government-funded consumer rebates. The rebate could simply be based on fuel economy (45). Another possibility is contests for creation of prototype vehicles meeting certain goals. Over the past century contests for new technological achievements have provoked very interesting creations. This approach could be invigorated with major government-funded contests.

A more refined policy incorporating features of both these approaches would be federal rebates applying to the initial production runs of vehicles meeting specified goals. Different goals could apply to different sizes of both cars and trucks.

It would probably be desirable to carry out such policies in combination: both to encourage consumers to buy early versions of vehicles incorporating new technology and to prepare manufacturers to carry out such technological change (46). In the late 1970s the government presciently helped manufactur-

ers prepare for the second oil shock with the 1975 CAFE legislation (47), but sales of the new vehicles were poor. Would rebates to smooth the way for the new technology have helped? Might the associated economic dislocation have been moderated? One does not know. There has been little evaluation of past policies to guide the formulation of new policies.

OTHER PASSENGER TRANSPORTATION ISSUES

Alternative Fuels

Alternative fuels for personal passenger vehicles is currently a hot topic. With the decline in oil prices and the difficulties of synfuels programs, interest in a synthetic gasoline has declined in the United States, but metropolitan-region air pollution has sharpened interest in fuels composed of simpler molecules, whose products are less reactive in the atmosphere. There are major efforts elsewhere with ethanol, natural gas, and LPG as motor vehicle fuels. At a more theoretical level, interest in hydrogen and electricity continues. (Much developmental work on electric vehicles has gone on in the United States, but there is as yet no hint of practical vehicles for other than small niche markets.)

Methanol enjoys the most attention in the United States at present. Some of this attention is due to the fact that modified vehicles can burn (without attention by the driver) widely varying mixtures of methanol and gasoline, thus potentially easing aspects of a transition to methanol. For example, methanol could be favored in certain air-quality regions and gasoline elsewhere. A disadvantage of this approach is that such flexible-fuel vehicles would not be designed to take advantage of the specific properties of the methanol, a substantial sacrifice. Another approach to flexible fuel capability is presented in the paper by Mellde et al (48) in this volume.

Congestion

Metropolitan area transportation is burdened by congestion. Moreover, street and highway mileage continues to grow more slowly than vehicle-miles. Only a small fraction of passenger-miles can be diverted to mass transit in the foreseeable future. Moreover, the energy-intensity of mass transit per passenger-mile may not be much less than that of the private car. Mass transit can, however, relieve congestion and can influence real-estate development so as to reduce dependence on personal vehicles. Some evidence of this is that motor vehicle-miles per adult is two thirds as great in New York and Illinois as it is in Texas. (Another response to congestion, information and control systems for highways, is not discussed.)

Intercity passenger travel faces even more severe congestion. Traveling in three dimensions is, paradoxically, much more affected by crowding than traveling in two. There is a technologically exciting opportunity: high-speed

ground transportation. The concept is to replace short-haul heavily traveled air routes with high-speed ground vehicles. The main focus would be substitution for air travel, including longer-distance travel where a ground trip, e.g. between Detroit and Chicago airports, would be combined with a flight (private communication, Larry R. Johnson). An energy-efficient lightweight vehicle and guideway might be enabled by magnetic levitation. Such vehicles might be able to operate along expressway rights of way.

The energy implications of such developments are of course quite uncertain. Nevertheless, we know that the technological ferment of our times is counterbalanced by the capital-intensity of transportation, including not only the equipment directly involved, but the equipment of suppliers including, especially, energy suppliers. Moreover, inertia is created not only by physical capital but also by human capital, our organizations, modes of operation, and knowledge. This suggests that although modifications of existing systems can be achieved in relatively short times (such as the improvement of in-use automotive fuel economy and the increase of the average passenger capacity per airplane of commercial airlines since the early 1970s), more profound changes will take longer. They will take longer especially if they are motivated by concerns other than improvement in the service provided.

CONCLUSIONS

This wide-ranging discussion was intended as an antidote to the concept of autonomous energy demand, i.e. the concept that demand is not subject to ordinary policy making the way supply is. Even without considering modal switching or alternative fuels, there is great uncertainty in the energy requirements for transportation. Moreover, that uncertainty is not only associated with hard-to-control factors such as the world oil price and consumer tastes, it also depends sensitively on the energy-efficiencies of the technologies used. These technologies will, in turn, depend on what the manufacturers choose to develop and market and on public policies. There are public policies, with which we already have experience, that (in the author's opinion) are not economically severe and that do not severely intrude on private decision-making, that would probably have powerful impacts on transportation technologies and energy use during the first decade of the next century.

An exercise by the author to quantify the uncertainty in personal-passenger-vehicle energy use in 2010 yielded high and low scenarios, with energy use in the high scenario twice as high as in the low scenario. These diverse outcomes are the result of moderate, unsurprising developments and choices. The point is that energy demand is, to a critical degree, a matter for rational decisionmaking, rather than simply being an act of God or the consequence of a particular fuel-price elasticity—if one looks ahead far enough in the future so

that there is time to make decisions (at normal replacement times) about the capital equipment involved.

ACKNOWLEDGMENTS

I would like to thank H. S. Geller, K. H. Hellman, M. R. Ledbetter, J. D. Murrell, and D. J. Santini for many helpful comments and D. A. Stukenborg for comments and assistance. I also thank the Joyce Foundation for partial support of the work.

Literature Cited

1. Energy Inf. Admin. *Monthly Energy Review* and *Annual Energy Review*. US Dept. Energy
2. Holcomb, M. C., Floyd, S. D., Cagle, S. L. 1987. *Transportation Energy Data Book. ORNL-6325*. Oak Ridge Natl. Lab. 9th ed.
3. Davis, S. C., Shonka, D. B., Hu, P. S. 1988. *Automated Transportation Energy Data Book*. Draft Report. Oak Ridge Natl. Lab.
4. US Bur. Census. 1984. *Truck Inventory and Use Survey*. 1982. Census of Transportation. US Dept. Commerce
5. Energy Inf. Admin. 1987. *Consumption Patterns of Household Vehicles 1985*. Residential Transportation Energy Consumption Survey. US Dept. Energy
6. Motor Vehicle Manufacturer's Assoc. 1987. *Facts and Figures*. Detroit, Mich.
7. Fed. Highway Admin. Annual. *Highway Statistics*. US Dept. Transportation. Table VM-1
8. Miller, M., Vyas, A. 1985. *Transportation Energy Demand From 1980 to 2010: The ANL-85N2 Forecast. ANL/CNSV-TM-169*. Argonne Natl. Lab.
9. Miller, M., Singh, M., Vyas, A., Johnson, L. R. 1987. *Transportation energy outlook under conditions of persistently low petroleum prices*. Presented at 66th Annu. Meet. Transportation Res. Board, Argonne Natl. Lab.
10. Energy and Environmental Analysis, Inc. 1987. *The Motor Fuel Consumption Model*. 13th Periodical Report. Arlington, Va.
11. US Bur. Census. 1972. *Truck Inventory and Use Survey*. Census of Transportation. US Dept. Commerce
12. Williams, R. H., Larson, E. D., Ross, M. H. 1987. Materials, affluence and industrial energy use. *Annu. Rev. Energy* 12:99–144

12a. Boyd, G., McDonald, J. F., Ross, M., Hanson, D. A. 1987. Separating the changing composition of U.S. manufacturing production from energy efficiency improvements: a Divisia index approach. *Energy J.* 8:77–96. April

13. Fed. Highway Admin. Monthly. *Traffic Volume Trends* US Dept. Transportation
14. Werbos, P. 1986. Documentation of the Transportation Energy Demand (TED) Model as Used in the *Annual Energy Outlook (1985). DOE/EIA-MO13* US Dept. Energy
15. Fed. Highway Admin. 1986. Personal Travel in the U.S. (2 vols.). *Nationwide Personal Tranportation Study, 1983–84*. US Dept. Transportation
16. Heavenrich, R. M., Murrell, J. D., Cheng, J. P. 1987. Light-duty automotive fuel economy and technology trends through 1987. *SAE 871088*
17. Heavenrich, R. M., Murrell, J. D. 1988. Light-duty vehicle automotive technology and fuel economy trends through 1988. Technical Report, Motor Vehicle Emissions Lab. Ann Arbor, Mich: US Environ. Protection Agency
18. Greene, D. L. 1986. Efficiency related changes in automobile and light truck markets, 1978–1986. *SAE 861423*
19. Hu, P. S., Buckels, L. S. 1987. Motor vehicle mpg and market share report: model year 1986. *ORNL-6351*. Oak Ridge Natl. Lab.
20. Hu, P. S., Williams, L. S. 1988. Light duty vehicle mpg & market share report: first six months of model year 1988. *ORNL-6496* Oak Ridge Natl. Lab.
21. Patterson, P. D. 1987. Periodic Transportation Energy Report No. 1. Unpublished memo of Nov. 16, 1987. US Dept. Energy
22. Hellman, K. H., Murrell, J. D. 1984. Development of adjustment factors for the EPA city and highway mpg values. *SAE 840496*
23. Am. Physical Soc. 1975. Study of the technical aspects of more efficient use of energy. *Efficient Use of Energy*. Part I. Ch. 4. *Am. Inst. Physics Conf. Series*, 25

24. Cole, D. E. 1984. Automotive fuel economy. In *Fuel Economy in Road Vehicles Powered by Spark Ignition Engines*, ed. J. C. Hilliard, G. S. Springer. Plenum
25. Seiffert, U., Walzer, P. 1984. *The Future for Automotive Technology*. London: Pinter
26. Bleviss, D. L. 1988. *The New Oil Crisis and Fuel Economy Technologies: Preparing the Light Transportation Industry for the 1990s*. New York. Quantum Books. 268 pp.
27. Gray, C. L., von Hippel, F. 1981. The fuel economy of light vehicles. *Sci. Am.* 244:48–56. (May)
28. Lenz, H. P., Wichart, K., Grudent, A. 1988. Variable valve timing—a possibility to control engine load without throttle. *SAE 880388*
29. Duret, P., Ecomard, A. 1988. A new two-stroke engine with compressed-air assisted fuel injection for high efficiency low emissions applications. *SAE 880176*
30. Nuti, M. 1988. Direct fuel injection: Piaggio approach to small 2T SI engines. *SAE 880172*
31. Plohberger, D., Mikulic, L., Landfahrer, K. 1988. Development of a fuel injected two-stroke gasoline engine. *SAE 880170*
32. Kummer, J. T. 1984. Fuel economy & emissions. See Ref. 24
33. Energy and Environmental Analysis, Inc. 1986. Analysis of the Capabilities of Domestic Auto-Manufacturers to Improve Corporate Average Fuel Economy. A Report to Office of Policy, Planning and Analysis, Arlington, Va: US DOE
34. Duleep, K. G. 1988. Presentation at *Off. Technol. Assessment Workshop Sept. 13, 1988*, by Energy and Environmental Analysis inc. Arlington, Va.
35. Horton, E. J., Compton, W. D. 1984. Technological trends in automobiles. *Science* 225:587–93
36. von Hippel, F., Levi, B. G. 1983. Automobile fuel efficiency: the opportunity and the weakness of existing market incentives. *Resources and Conservation* 10:103–24
37. Baltagi, B. H., Griffin, J. M. 1984. U.S. gasoline demand: what next? *The Energy J.* 5(1):129–40
38. Bohi, D. R., Zimmerman, M. B 1984. An update on economic studies of energy demand. *Annu. Rev. Energy* 9:105–54
39. Greene, D. L. 1988. Transportation efficiency and alternative fuels: the road to the future. Presented at *ACEEE Summer Study on Energy Efficiency in Buildings, Asilomar, Calif.*
40. McNutt, B. D., Patterson, P. D. 1986. CAFE standards—is a change in form needed? *SAE 861424*
41. Int. Energy Agency. 1988. *Energy Prices and Taxes, Second Quarter 1988*. Paris: Org. Econ. Coop. Dev.
42. Motor Vehicle Emissions Lab. 1985. *Compilation of Air Pollutant Emission Factors*. Vol. 11: *Mobile Sources*. Ann. Arbor, Mich: US Environ. Protection Agency
43. Am. Council for an Energy Efficient Econ. 1987. *The Role of Federal Research and Development in Advancing Energy Efficiency*. Washington, DC
44. Natl. Acad. Sci. 1982. *The Competitive Status of the U.S. Auto Industry*
45. Chandler, W. U., Geller, H. S., Ledbetter, M. R. 1988. *Energy Efficiency: A New Agenda*. Am. Council for an Energy Efficient Econ. Washington, DC
46. Santini, D. J. 1984. Watch auto technology, fuel prices to forecast slumps. *The J. Business Forecasting: Methods & Systems*. Fall 1984, pp. 18–26
47. Santini, D. J. 1986. *The Petroleum Problem: Managing the Gap*. Vol. 2—*Full Report* (report *ANL/CNSV-58*, vol. 2) Argonne Natl. Lab.
48. Mellde, R. W., Maasing, I. M., Johansson, T. B. 1989. Advanced automobiles for fuel economy, low emissions, and multifuel capability. *Annu. Rev. Energy* 14:425–44

Chapter 3
Energy Use and Economic Variables

by Richard S. Mack and H. F. McDuffie

I. Introduction

Because increases in energy use have historically accompanied economic growth, it is tempting to think of the two variables as directly correlated. However, attempts to specify and quantify their relationships have led to discrepancies of magnitude and often of direction. It seems clear that economic activity not only affects energy use, but the availability of energy and the ways in which it is used affect a number of economic variables.

This chapter examines several aspects of the energy/economy relationship. Section I is an overview of changes in historical patterns of energy use. Section II considers the quantification of the relationship between gross national product (GNP) and energy inputs. Section III views the explicit microeconomic relationship between energy price and quantity used in the industrial sector.

II. Historical Perspective

The history of industrial civilization has been the history of man's ability to acquire, use, and control sources of energy and power beyond those derived from human and animal muscle or the limited use of water power for mechanical energy. Energy use increased from a per capita consumption of 2,000 kilocalories per day associated with basic food consumption in a hunting and gathering society to 12,000 kilocalories per day under primitive agriculture. During the period of the low-technology industrial revolution (1850–1870), usage reached 70,000 kilocalories per day; in the United States current per capita usage is 276,160 kilocalories per day.[1]

The acceleration in energy use is usually associated with the development of steam as a prime mover in the industrial sector. The associated development of steel technology and rail transport is directly linked to the mobility of steam power relative to the stationary nature of water power.[2] Just as the use of coal extended the industrial horizon and stopped the destruction of the forests of Western Europe and North America, the later discovery of technologies for recovering and using petroleum and natural gas led to further industrial advances including the internal combustion engine and the steam and gas turbine. Each of these developments reinforced the pattern of accelerating use of energy, which was coupled with increases in the demands for industrial output.

The U.S. has been extravagantly blessed with plentiful and easily available resources. With only limited restrictions on exploitation, the U.S. has been using these resources, especially petroleum, at a high and accelerating rate. Figure 3.1 shows the historical trends in fuel consumption. A cogent historical perspective is given by M. King Hubbert, in his comments on fossil fuels:

> If these substances [fossil fuels] continue to be used principally for their energy contents, and if they continue to supply the bulk of the world's energy requirements, the time required to exhaust the middle 80% of the ultimate resources of the

1. Earl Cook, "The Flow of Energy in an Industrial Society," *Scientific American* 224, no. 3 (September 1971).
2. Chauncey Starr, "Energy and Power," *Scientific American* 224, no. 3 (September 1971).

105

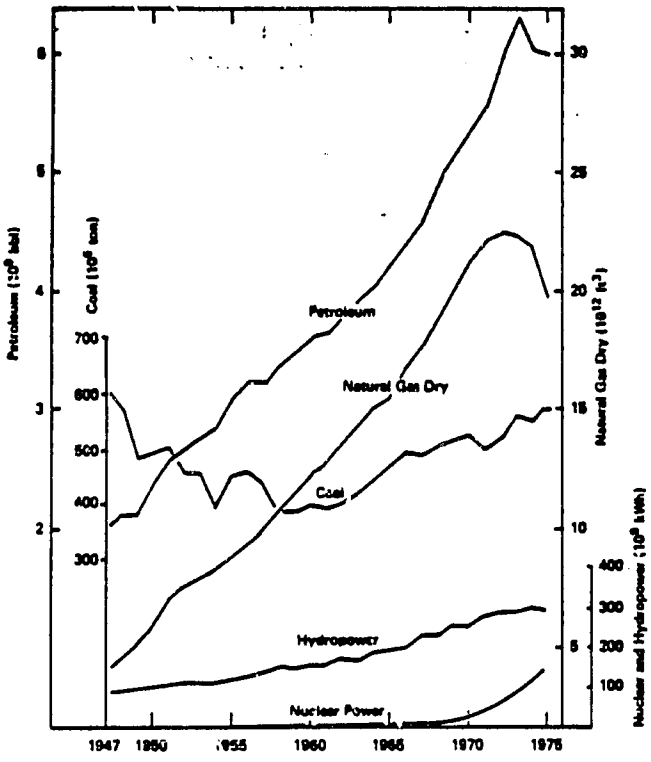


Figure 3.1. U.S. gross consumption of mineral energy resources and electricity from hydropower and nuclear power in physical units, 1947–1975. Levels for 1975 are projected.

Source: U.S. Energy Research and Development Administration, *Administrator's Energy Data Book* (July 1976), p. 201.

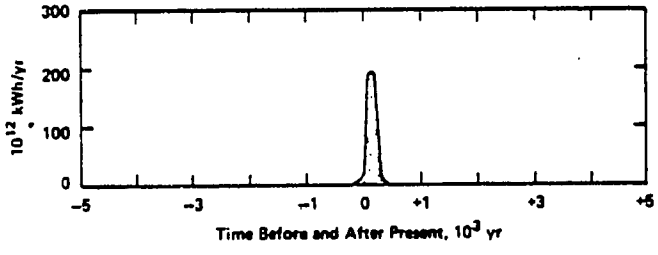


Figure 3.2. Complete cycle of world consumption of fossil fuels on a time scale of 5,000 years before and after the present

Source: Reprinted with permission from M. King Hubbert, "Man's Conquest of Energy: Its Ecological and Human Consequences." In *The Environmental and Ecological Forum, 1970–1971* (Washington, D.C.: U.S. Atomic Energy Commission, Office of Information Services, 1972), p. 17.

members of the petroleum family—crude oil, natural gas and natural gas liquids, tar-sand oil, and shale oil—will probably be only about a century.

Under similar conditions, the time required to exhaust the middle 80% of the world's coal resources would be about 300 to 400 years (but only 100 to 200 years if coal is used as the main energy source).

To appreciate the bearing of these conclusions on the long-range outlook for human institutions, the historical epoch of the exploitation of the world's supply of fossil fuels is shown graphically in [Figure 3.2], where the rate of production of the fossil fuels as a function of time is plotted on a time scale extending from 5,000 years ago to 5,000 years in the future—a period well within the prospective span of human history. On such a time scale, it is seen that the epoch of the fossil fuels can only be a transitory and ephemeral event—an event, nonetheless, which has exercised the most drastic influence experienced by the human species during its entire biological history.[3]

Thus, in the long run, or even in the moderately short run of only a few generations, we are following a course that is most certain to exhaust our resources of easily available fossil fuels. This consumption is aggravated by the world population explosion and the rising expectations of members of the Third World. Solar and other forms of renewable energy, including biomass not requiring synthetic fertilizer, can certainly contribute in substituting for fossil fuels. Other conservation measures likewise can reduce our consumption and raise the ratio of gross domestic product (GDP) to energy used.[4]

The expansion of the world's economy has been largely based on a long decline in the price of energy. Figure 3.3 shows the recent history of the real price of industrial energy and the very abrupt rise beginning in 1973 with the increase in the price of oil from the Organization of Petroleum Exporting Countries (OPEC) accompanied by increases in the prices of coal and natural gas.

3. M. King Hubbert, "Energy Resources." Chapter 8 of *Resources and Man* (San Francisco: W. H. Freeman and Co. for National Academy of Sciences, National Research Council, 1969), p. 205.

4. GDP equals gross national product (GNP) less net property income from abroad.

106

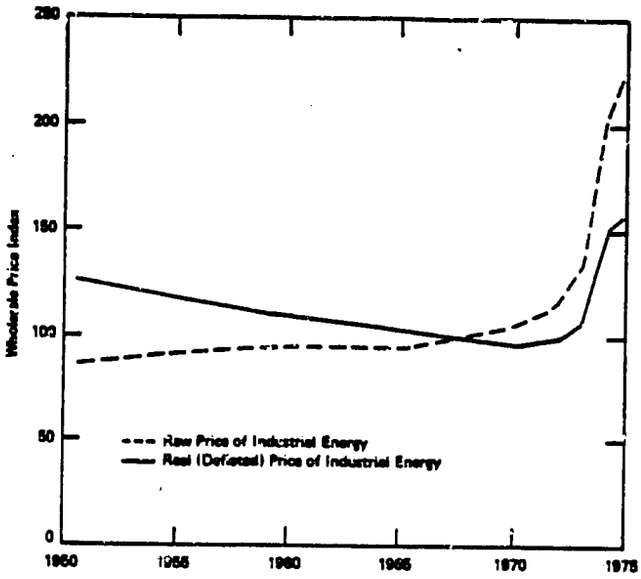


Figure 3.3. History of real energy price

Source: R. W. Barnes; printed in National Research Council, *Alternative Energy Demand Futures to 2010*, The Report of the Demand and Conservation Panel to the Committee on Nuclear and Alternative Energy Systems (CONAES) (Washington, D.C.: National Academy of Sciences, 1979), Figure 22, p. 98.

III. Relationship of Energy to Economic Output

Because energy is a factor of production, it relates as both a substitute and a complement to other factors of production, depending upon the length of time of the analysis. Because of the high levels of unemployment experienced over the past decades, the relationship between labor and energy intensity is of particular concern. Figure 3.4 portrays the relationship between energy intensity and labor intensity for a number of industrial products. Note that energy and labor usages are in part determined by the product mix within the economy. The energy and labor quantities of Figure 3.4 are based upon the total requirements (direct and indirect) to effect marginal changes in final demand.

With respect to the variables of energy use and sectoral economic growth, Figure 3.5 shows the effect of 10% growth of each industry upon energy use and employment in the entire economy. Note that first quadrant industries show a complementary relationship and are primarily agricultural. Growth in industries in the second quadrant is accompanied by expansion of total energy use and contraction of employment in the entire economy; these second quadrant industries primarily produce basic materials. Third quadrant industries show simultaneously negative changes in both labor and energy use, reflecting the use of technologies that are labor saving, but not energy intensive, as inputs to increased production. This situation contrasts with quadrant four, where low wages reduce the need for labor-saving technology. It is noteworthy that over half of the industries fall into quadrant two, indicating the substitution effect associated with sectoral growth.[5]

As for the relationship of energy and total output, Figure 3.6 shows the relatively steady increases in both variables. The late downturn in both energy consumption and GNP is a function of the 1973 oil embargo and the reduced levels of economic activity during the 1974–1975 recession.

The expanded scale in the lower part of Figure 3.6 shows the ratio of energy use to GNP, expressed in watt-years per dollar (Wyr/$). All the changes shown fall within a range of ± 5% and, thus, may not be significant. Nevertheless, the decrease in the ratio until 1966 is a continuation of a general trend which began in 1920. Reduction of the ratio of energy to GNP during this period is explained by increases in the efficiency of energy conversion and by growth by the service sector, which is a less energy-intensive contributor to GNP. Since 1967, the increase in the ratio may be due to the substitution of electricity for many direct fuel uses, as well as the rapid growth of air conditioning as a primary electrical use that has little multiplier effect on GNP.[6] The 1970–1972 peak is associated with the flat portion of the GNP curve above. Since the oil embargo, higher energy costs and resultant decreases in efficiency (from general business slowdown and from use of sources that are less energy efficient) may be causing an upturn in the ratio; continued increases in energy cost should eventually force a less energy-intensive industry mix.

The relationship between energy consumption per capita and the gross domestic product of nations is shown in Figure 3.7. Naturally, there is some variation among nations with regard to this relationship, because nations have differing amounts of various resources, investment capital, and labor, and different cultures and life-styles.

5. Bruce Hannon, "An Energy Standard of Value," *The Annals of the American Academy of Political and Social Science*, no. 410 (1973), pp. 139–52.
6. Cook, "The Flow of Energy in an Industrial Society."

107

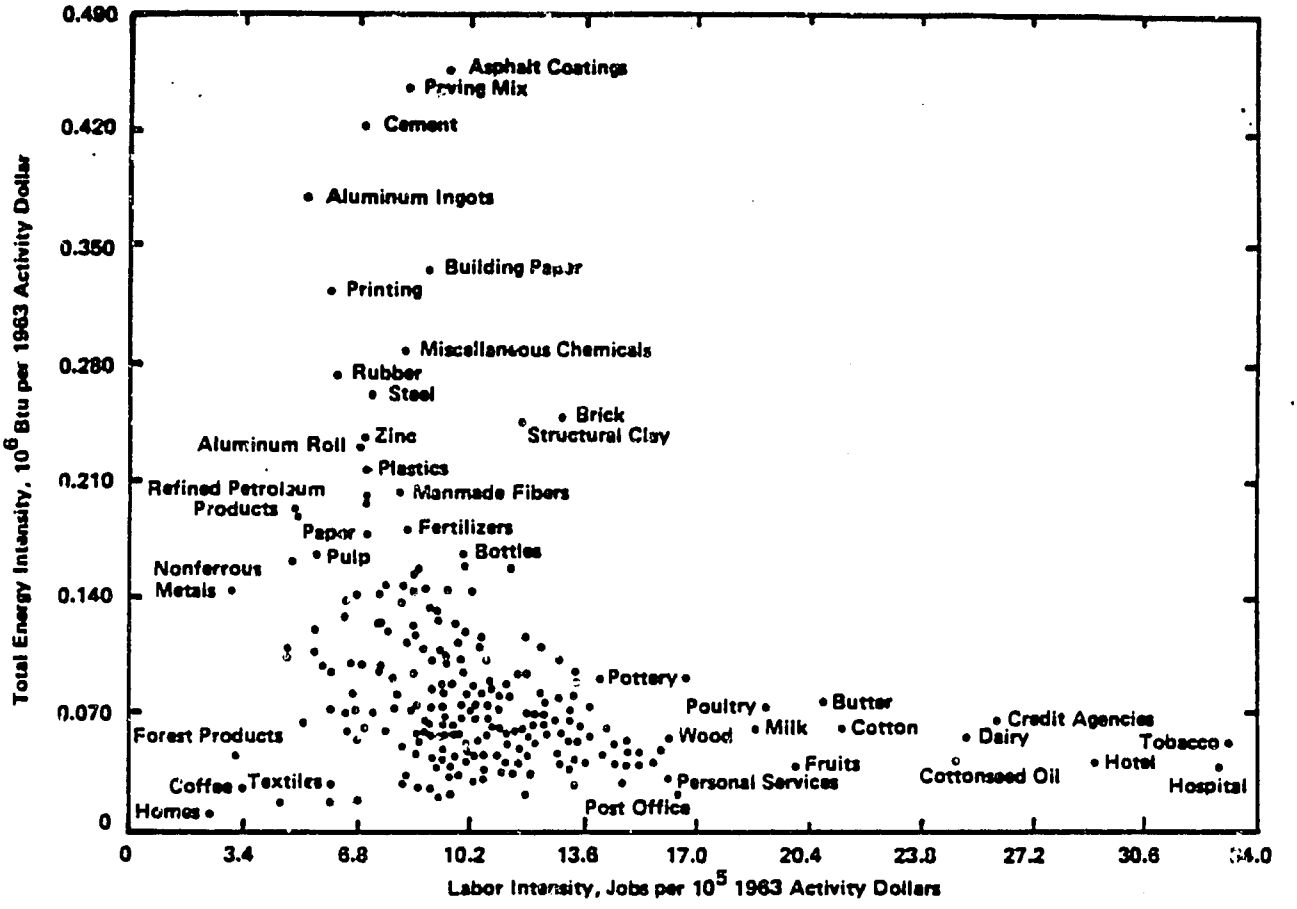


Figure 3.4. Total (direct and indirect) energy and employment intensities for all U.S. industrial sectors, 1963

Source: Bruce Hannon, "An Energy Standard of Value." In Library of Congress, Congressional Research Service, *Energy Accounting as a Policy Analysis Tool* (Washington, D.C.: 1976), p. 29.

108

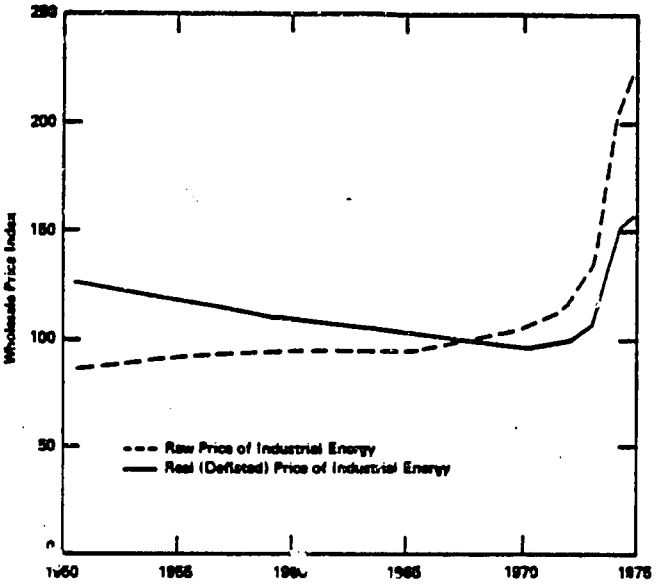


Figure 3.3. History of real energy price

Source: R. W. Barnes; printed in National Research Council, *Alternative Energy Demand Futures to 2010*, The Report of the Demand and Conservation Panel to the Committee on Nuclear and Alternative Energy Systems (CONAES) (Washington, D.C.: National Academy of Sciences, 1979), Figure 22, p. 98.

III. Relationship of Energy to Economic Output

Because energy is a factor of production, it relates as both a substitute and a complement to other factors of production, depending upon the length of time of the analysis. Because of the high levels of unemployment experienced over the past decades, the relationship between labor and energy intensity is of particular concern. Figure 3.4 portrays the relationship between energy intensity and labor intensity for a number of industrial products. Note that energy and labor usages are in part determined by the product mix within the economy. The energy and labor quantities of Figure 3.4 are based upon the total requirements (direct and indirect) to effect marginal changes in final demand.

With respect to the variables of energy use and sectoral economic growth, Figure 3.5 shows the effect of 10% growth of each industry upon energy use and employment in the entire economy. Note that first quadrant industries show a complementary relationship and are primarily agricultural. Growth in industries in the second quadrant is accompanied by expansion of total energy use and contraction of employment in the entire economy; these second quadrant industries primarily produce basic materials. Third quadrant industries show simultaneously negative changes in both labor and energy use, reflecting the use of technologies that are labor saving, but not energy intensive, as inputs to increased production. This situation contrasts with quadrant four, where low wages reduce the need for labor-saving technology. It is noteworthy that over half of the industries fall into quadrant two, indicating the substitution effect associated with sectoral growth.[5]

As for the relationship of energy and total output, Figure 3.6 shows the relatively steady increases in both variables. The late downturn in both energy consumption and GNP is a function of the 1973 oil embargo and the reduced levels of economic activity during the 1974–1975 recession.

The expanded scale in the lower part of Figure 3.6 shows the ratio of energy use to GNP, expressed in watt-years per dollar (Wyr/$). All the changes shown fall within a range of ± 5% and, thus, may not be significant. Nevertheless, the decrease in the ratio until 1966 is a continuation of a general trend which began in 1920. Reduction of the ratio of energy to GNP during this period is explained by increases in the efficiency of energy conversion and by growth by the service sector, which is a less energy-intensive contributor to GNP. Since 1967, the increase in the ratio may be due to the substitution of electricity for many direct fuel uses, as well as the rapid growth of air conditioning as a primary electrical use that has little multiplier effect on GNP.[6] The 1970–1972 peak is associated with the flat portion of the GNP curve above. Since the oil embargo, higher energy costs and resultant decreases in efficiency (from general business slowdown and from use of sources that are less energy efficient) may be causing an upturn in the ratio; continued increases in energy cost should eventually force a less energy-intensive industry mix.

The relationship between energy consumption per capita and the gross domestic product of nations is shown in Figure 3.7. Naturally, there is some variation among nations with regard to this relationship, because nations have differing amounts of various resources, investment capital, and labor, and different cultures and life-styles.

5. Bruce Hannon, "An Energy Standard of Value," *The Annals of the American Academy of Political and Social Science*, no. 410 (1973), pp. 139–52.

6. Cook, "The Flow of Energy in an Industrial Society."

109

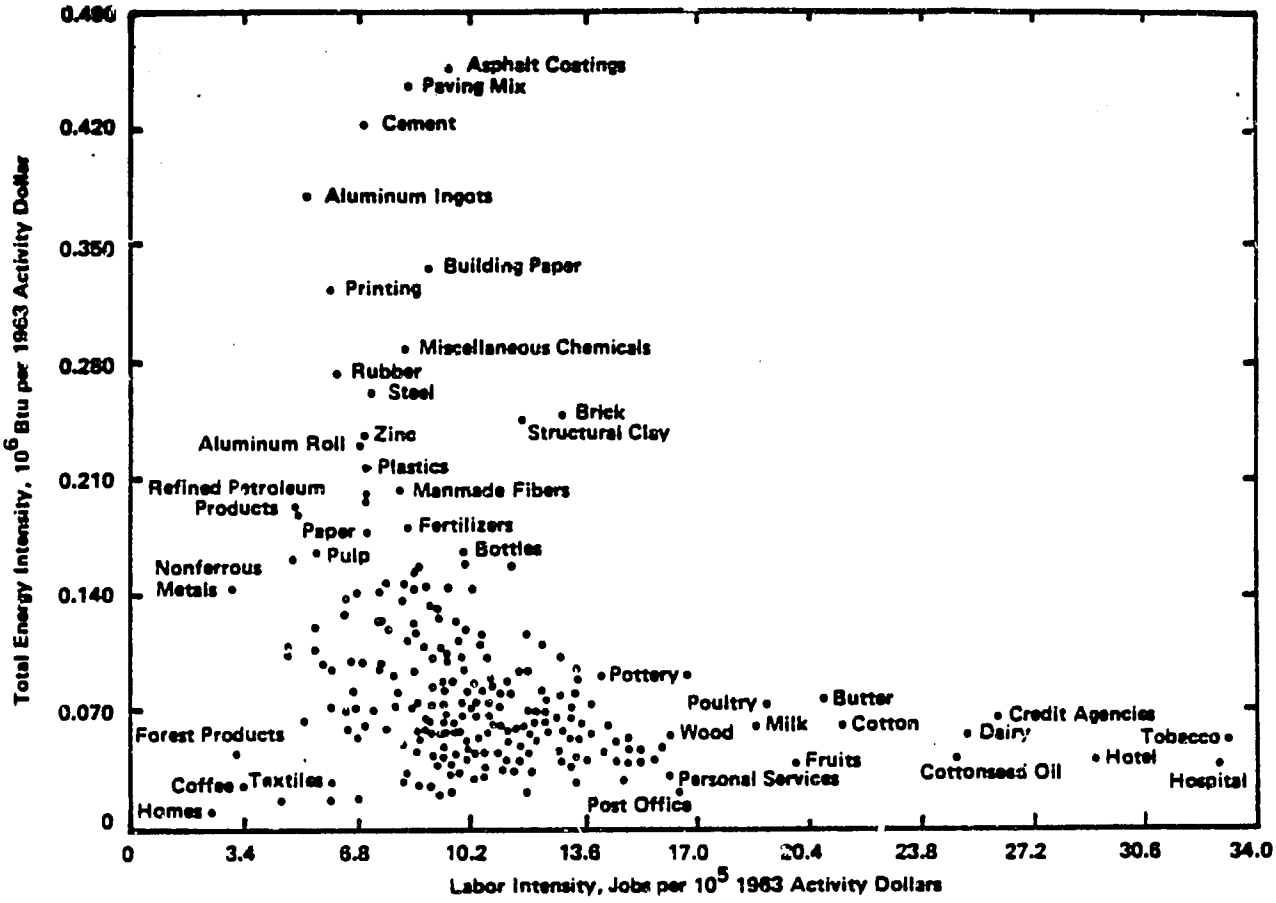


Figure 3.4. Total (direct and indirect) energy and employment intensities for all U.S. industrial sectors, 1963

Source: Bruce Hannon, "An Energy Standard of Value." In Library of Congress, Congressional Research Service, *Energy Accounting as a Policy Analysis Tool* (Washington, D.C.: 1976), p. 29.

110

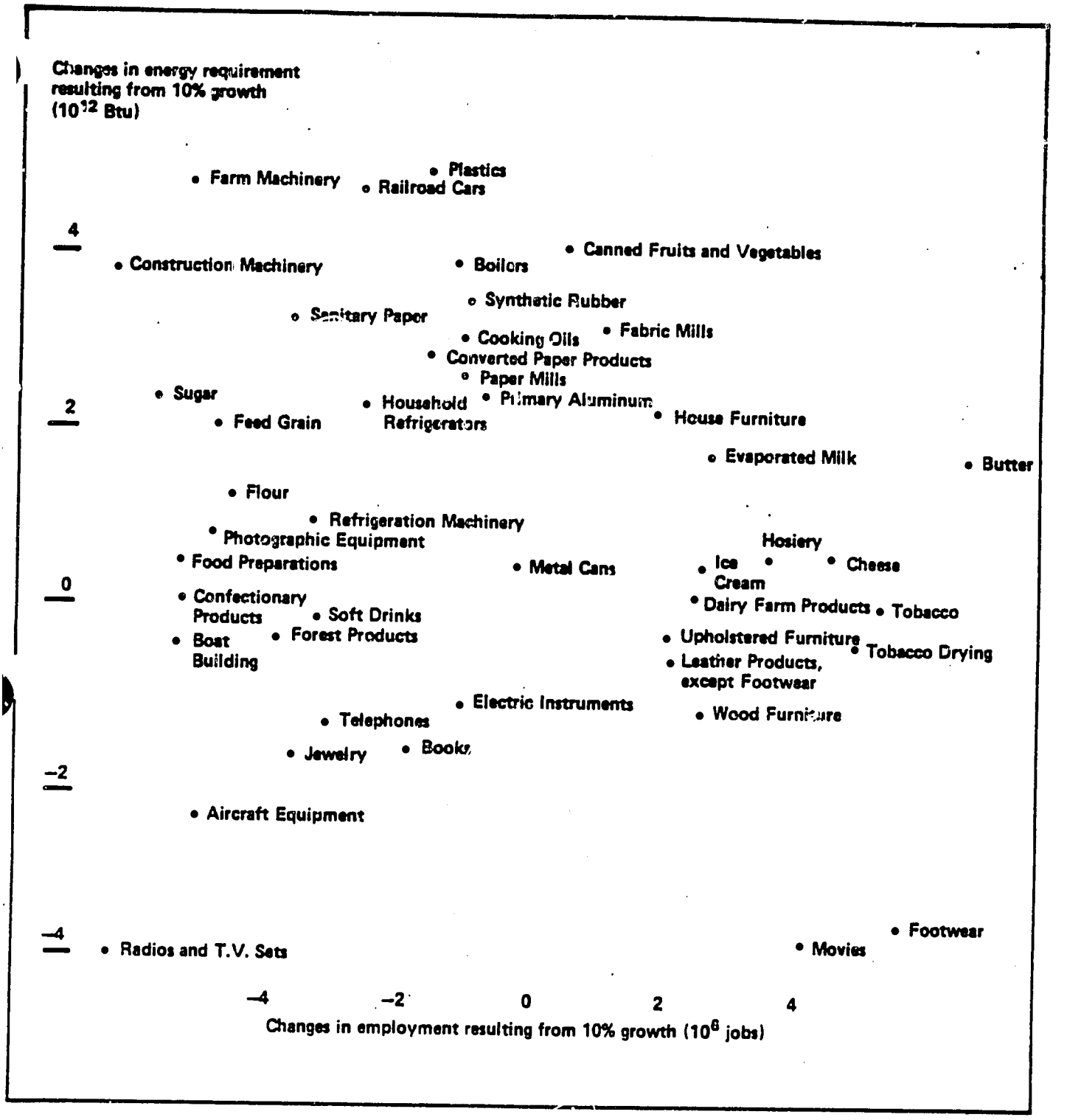


Figure 3.5. Employment-energy trade-offs: effects of differential growth in specific industries

Source: Reprinted with permission from Bruce Hannon, "Options for Energy Conservation," *Technology Review* (February 1974): 26.

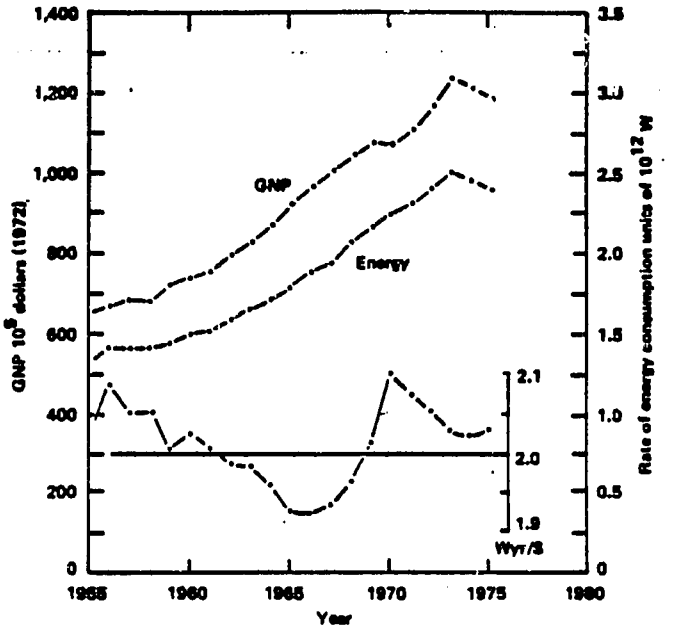


Figure 3.6. The correlation between energy consumption and economic activity, 1955–1975

Source: Reprinted with permission from Jerrold H. Krenz, "Energy and the Economy: An Interrelated Perspective," *Energy* 2, no. 2 (June 1977): 116. ©1977 Pergamon Press Ltd.

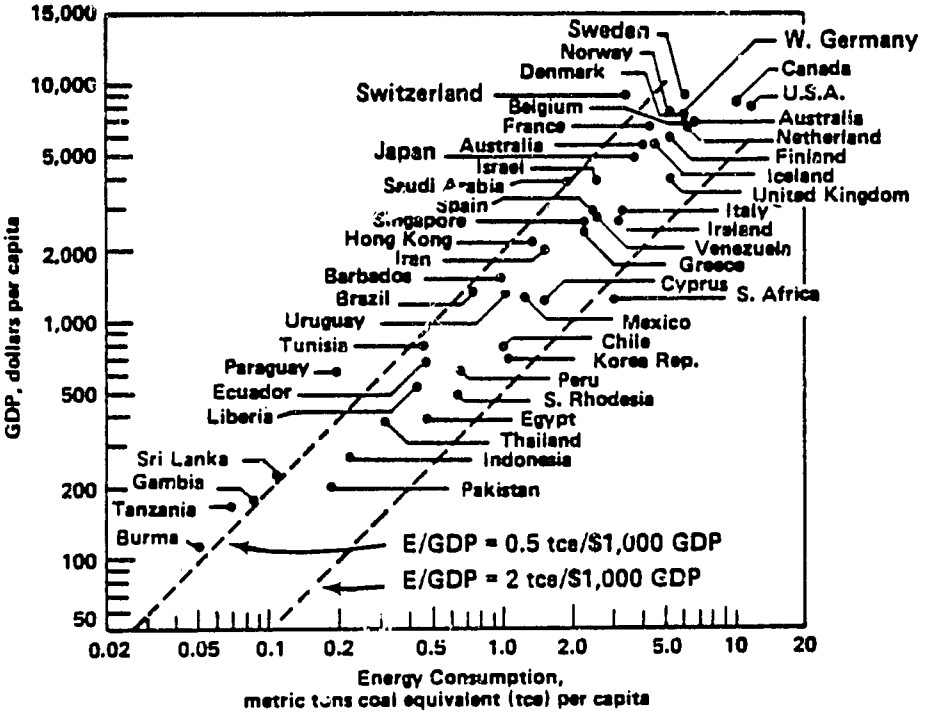


Figure 3.7. Relationship between gross domestic product and energy consumption per capita for 48 countries, 1976

Source: U.N. data; printed in Henry R. Linden, Joseph D. Parent, and J. Glenn Seay, *Perspectives on U.S. and World Energy Problems* (Chicago: Institute of Gas Technology, February 1979), frame 5.

112

IV. Responsiveness of Industrial Energy Use to Variations in Energy Prices and Sectoral Output

Price elasticity of demand is an analytic measure of the responsiveness of quantity demanded to changes in price. More specifically, the coefficient of price elasticity represents the percentage response in quantity demanded which results from a given percentage change in price. Simple or "own" price elasticities are always negative, indicating an inverse relationship in that an increase in price will decrease the quantity demanded.

Demand is deemed "elastic" if a given percentage change in price results in a larger percentage change in quantity demanded. This situation represents a high degree of responsiveness to price change. Elastic conditions are indicated by a coefficient of elasticity which falls between -1 and $-\infty$. On the other hand, if a given percentage change in price results in a smaller percentage change in quantity demanded, then the relationship is termed "inelastic"; inelasticity is denoted by a coefficient which ranges between 0 and -1. In the industrial sector, relative inelasticity in the demand for energy, particularly in the short run, results from the technical inability to substitute other fuels in response to price increases. In the long run, when changes in capital equipment are possible, responsiveness tends to be more elastic. As for special cases, a coefficient of 0 indicates no response to a change in price, whereas a coefficient of -1 indicates a situation of percentage changes in quantity that are equal to the initiating changes in prices.

Price elasticities for energy demand in the industrial sector are presented in Tables 3.1 through 3.5. Table 3.1 treats energy in the aggregate, whereas Tables 3.2 through 3.5 treat electricity, coal, natural gas, and petroleum. Although there are great variations in magnitude, there are no zero elasticities; this fact attests to the concept that quantity demanded responds to changes in price. Similarly, the tables show energy demand to be more inelastic in the short run, reflecting the inability to substitute other fuels without time-consuming capital investment.

Right-hand columns of Table 3.1 through 3.5 list output elasticities, which reflect the percentage change in quantity demanded that results from a change in industrial sector output. These figures are positive because of the direct relationship between the variables.

Table 3.1. Price and Output Elasticities for Aggregate Energy, Industrial Sector

	Data		Price Elasticity[b]		Output Elasticity[b]	
Study	Type[a]	Vintage	Short-Run	Long-Run	Short-Run	Long-Run
Hudson-Jorgenson (1974)	TS:USA	1947–71	−0.05		1.00[c]	
Berndt-Wood (1975)	TS:USA	1947–71	−0.47		1.00[c]	
Baughman-Zerhoot (1975)	TS-CS: USA States	1950–72	−0.22		0.69	
Griffin-Gregory (1976)	CS-TS: USA and Europe	1955, '66 1965, '69	−0.79		1.00[c]	
Halvorsen (1976c)	TS:USA	1947–71	−0.28	−0.42	0.10[d]	1.00[c]
FEA (1976)	TS-CS: USA States	1960–72	−0.13	−0.31	1.00[c]	1.00[c]

a TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled CS and TS data.

b Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.

c Value is unity by the assumption.

d This elasticity is not necessarily compatible with the assumption of a Cobb-Douglas production function.

Source. James A. Edmonds. *A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies* (Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978. ORAU IEA-78-15(R)), p. 14.

Table 3.2. Price and Output Elasticities for Electricity, Industrial Sector

Study	Data		Price Elasticity[b]		Output Elasticity[b]		Type[c] of Price
	Type[a]	Vintage	Short-Run	Long-Run	Short-Run	Long-Run	
Fisher-Kaysen (1962)	CS:States	1946–57		−1.25			A
Baxter-Rees (1968)	TS: Indus. U.K.	1954–64	−1.50				A
Anderson (1971)	CS:States	1958, '62		-1.94			A
Mount-Chapman-Tyrrell (1973)	CS-TS: States	1947–70	−0.22	−1.82			A
Lyman (1973)	CS-TS: Areas served by utilities	1959–68	−1.40				A
Griffin (1974)	TS:Aggregate U.S.	1951–71	−0.04[e]	−0.51[e]			A
Hudson-Jorgenson (1974)	TS:USA	1947–71	−0.07		1.00[d]		A
Uri (1975)	TS:Monthly Aggregate U.S.		−0.35	−0.69	1.32	2.63	A
Baughman-Zerhoot (1975)	CS-TS: 48 States and Wash., D.C.	1962–72	−0.11	−1.28	0.69		A
Chern (1975a)	CS-TS: 16 U.S. Industries	1959–71	−0.61	−1.98	0.30	0.97	A
FEA (1976)	CS-TS: U.S. Census regions annual	1960–72	−0.15	−1.03	1.00[d]	1.00[d]	A
Halvorsen (1976a)	CS:States	1969		−1.24		0.68	M*
Halvorsen (1976b)	CS:USA States	1971		−0.92		1.00[d]	A

a. TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled CS and TS data.

b. Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.

c. M* refers to a theoretical model in which both average and marginal price elasticities are identical (price data was, however, either A or A*); A to an average price for electricity; and A* to an average price for a fixed amount of electricity.

d. Value is unity by the assumption.

e. Combined industrial and commercial.

Source: James A. Edmonds. *A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies* (Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978; ORAU/IEA-78-15(R)), p. 16.

114

Table 3.3. Price and Output Elasticities for Coal, Industrial Sector

Study	Data		Price Elasticity[b]			Output Elasticity[b]		
	Type[a]	Vintage	Short-Run		Long-Run	Short-Run		Long-Run
Reddy (1974)	TS:USA	1957–73	−0.39		−0.91	0.53		0.60
Hudson-Jorgenson (1974)	TS:USA	1947–71		−0.01			1.00[c]	
Lin-Spore-Nephew (1975)	TS:USA	1957–73		−0.49			0.56	
FEA (1976)	CS-TS USA States	1960–72	−0.44[d]		−0.73[d]	1.00[c]		1.00[c]
Halvorsen (1976b)	CS:USA States	1971			−1.52			1.00[c]

a. TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled CS and TS data.

b. Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.

c. Value is unity by the assumption.

d. This elasticity refers only to steam coal.

Source: James A. Edmonds, *A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies* (Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978; ORAU/IEA-78-15(R)), p. 18.

Table 3.4. Price and Output Elasticities for Natural Gas

Study	Data		Price Elasticity[b]			Output Elasticity[b]		
	Type[a]	Vintage	Short-Run		Long-Run	Short-Run		Long-Run
Vermetten-Plantinga (1953)	CS: States	1947			−2.11			
Villanueva (1964)	CS-TS: Regions	1950–60		−1.34~−1.64				
Felton (1965)	CS: States	1961			−1.50[c]			
Anderson (1971)	CS: States	1958, '62			−1.98			0.21
MacAvoy-Noll (1973)	CS: States				−1.78			0.68
Hudson-Jorgenson (1974)	TS:USA	1947–71		−0.04			1.00[d]	
Randall-Ives-Ryan (1974)	CS:USA S.W. Communities	1970			−3.85[e]			0.29[e]
MacAvoy-Pindyck (1973)	CS-TS: USA States	1964–70		−0.98~−1.13[f]				
Baughman-Zerhoot (1975)	CS-TS: USA States	1962–72	−0.07		−0.81		0.69	

115

Table 3.4. Price and Output Elasticities for Natural Gas — Continued

Study	Data		Price Elasticity[b]		Output Elasticity[b]	
	Type[a]	Vintage	Short-Run	Long-Run	Short-Run	Long-Run
FEA (1976)	CS-TS: USA States	1960–72	−0.17	−0.58	1.00[d]	1.00[d]
Halvorsen (1976b)	CS:USA States	1971		−1.47		1.00[d]

a. TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled CS and TS data.
b. Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.
c. Elasticity defined for a market share ratio between electricity and natural gas.
d. Value is unity by the assumption.
e. Aggregate commercial and industrial.
f. Saturation elasticity used.

Source: James A. Edmonds, *A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies* (Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978; ORAU/IEA-78-15(R)), pp. 19–20.

Table 3.5. Price and Output Elasticities for Petroleum

Study	Data		Price Elasticity[b]		Output Elasticity[b]	
	Type[a]	Vintage	Short-Run	Long-Run	Short-Run	Long-Run
Verleger-Sheehan (1974)			−0.12[c]	−0.61[c]	0.12[c]	0.61[c]
Hudson-Jorgenson (1974)	TS:USA	1947–71	−1.00[d]		1.00[d,h]	
			−0.02[e]		1.00[e,h]	
Baughman-Zerhoot (1975)	CS-TS: USA States	1962–72	−0.11	−1.32[d]	0.69[d]	0.69[d]
Houthakker-Kennedy (1975)	CS-TS: Nine OECD Countries	1965–70	−0.39[c]	−0.76[c]	1.43[c]	2.70[c]
			−0.17[f]	−2.37[f]	−0.21[f]	−2.84[f]
			−1.05[g]	−1.58[g]	0.40[g]	0.60[g]
FEA (1976)	CS:USA States	1971	−0.34[c]	−1.01[c]	1.00[c,h]	1.00[c,h]
			−0.26[g]	−0.75[g]	1.00[g,h]	1.00[g,h]
			−0.26[f]	−0.75[f]	1.00[f]	1.00[f]
Halvorsen (1976b)	CS:USA	1971		−2.82		1.00[h]

a. TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled TS and CS data.
b. Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.
c. Elasticities for distillate.
d. Crude petroleum products.
e. Elasticities for gasoline and oil.
f. Elasticity for kerosene.
g. Elasticity for residual oil.
h. Value is unity by the assumption.

Source: James A. Edmonds, *A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies* (Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978; ORAU/IEA-78-15(R)), p. 21.

116

Table 3.6 is a matrix of "own," and "cross" elasticities. The concept of "cross" elasticities refers to the responsiveness in the quantity demanded of one fuel to a change in price in another fuel. Thus, "cross" elasticity is a measure of substitutability; if the "cross" elasticity coefficient is positive, the two fuels are substitutes. For example, a coefficient of 0.75 in column 1, row 2, of Table 3.6 implies that, in response to a 10% increase in the price of oil, there is a positive increase of 7.5% in the quantity of gas demanded by industry; the fuels are substitutes. Lower "cross" elasticity coefficients in the second and third columns indicate a lesser degree of substitutability.

Table 3.6. Long-Run Elasticity/Cross-Elasticity Matrix for the Industrial Sector (Less Feedstocks)

Elasticity of Consumption of	In Response to a Price Change at the Point of Consumption in			
	Gas	Oil	Coal	Electricity
Gas	−0.81	0.14	0.15	0.34
Oil	0.75	−1.32	0.14	0.33
Coal	0.75	0.14	−1.14	0.33
Electricity	0.73	0.13	0.14	−1.29

Note: Mean values calculated for the following fuel consumption configuration: 52% natural gas; 19.5% oil; 7.4% coal; 21.1% electricity.

Source: M. L. Baughman and F. S. Zerhoot, *Energy Consumption and Fuel Choice by Industrial Consumers in the United States* (Cambridge, Massachusetts: MIT Laboratory, March 1975).

Chapter 5
Investment Criteria and Public Policies Toward Industrial Energy Conservation

by Richard S. Mack

This chapter considers the relationships between investment in industrial energy conservation and public policy measures designed to provide incentives for such investment. In all considerations of policymaking, the relationship between the public and private sectors is of primary importance. Because conservation furthers both private and public goals, it is the role of public policy to assure first that private conservation efforts are allowed to take place to the extent of purely private incentives, and then to extend the degree of conservation beyond the point of private optimality to the point of public sector optimality. Accordingly, this chapter will consider briefly the need for and benefits of conservation and then turn to a discussion of private sector investment criteria, barriers to optimization, and current public sector policies.

I. Conservation

By definition the word *conservation* implies the preservation and management of a limited physical stock. In the industrial sector conservation of fuels can be achieved by four methods of altering energy use patterns:

1. Reduction of energy use through "housekeeping practices" or short-term efficiencies
2. Reduction of use through the retrofitting of energy conservation equipment, not involving process change
3. Reduction of use through process change, a long-run measure
4. Reduction of energy cost by means of fuel substitution and cogeneration

The category of "housekeeping" changes refers to minor modifications of existing systems. These modifications involve leak-plugging in heating and cooling processes, the adjustment of systems not operating at design efficiency, and the employment of energy management techniques to optimize energy use over time, within the constraints of the existing capital structure. Housekeeping measures usually can be accomplished out of operating budgets; capital investment is not necessary. Because relatively low costs and a high rate of dollar savings are associated with the first incremental units of housekeeping changes, internal financial incentives have provided the impetus to initiate these practices.

Retrofitting describes modifications made to existing capital equipment to render it more energy efficient. The modifications are necessary in older equipment because of design inefficiencies, which were appropriate in view of low fuel costs at the time of the original investment. The category of retrofitting also includes some elements of fuel substitution—namely, whatever types of fuel substitution or energy cascading that can be accomplished without completely replacing the process equipment. The level of required investment for retrofitting varies greatly depending upon the nature of equipment purchased.

When investment criteria indicate a financial preference for capital revision over retrofitting operations, the industry may replace existing assets with new ones. These process changes may involve the substitution of new process technology for the pur-

118

pose of long-run economy in the total costs of operations. Specifically, when retrofitting cannot economically accomplish fuel substitutions, process changes may be necessary. Given the long functional life of capital equipment in major industrial processes, process change requires a major financial commitment, involving decisions that will affect the profits of the firm over decades of use. Table 5.1 shows the age of U.S. manufacturing capacity by sector; note the high percentage of plants that began first-year operations in 1950 or earlier.

Although internal private sector incentives arising from post-1973 energy price increases have led to considerable application of industrial housekeeping measures, all estimates point to further potential efficiencies available through all four measures of conservation. The estimates of industrial energy savings by use of current conservation technology range from 10 to 15%.[1] Tables 5.2 and 5.3 present potential savings and projected progress for the Voluntary Business Energy Conservation program. In order to realize these potential savings, consideration must be given to decision-making in the private sector and to the way that it is influenced by public sector policies.

II. Investment: Decision-Making in the Private Industrial Sector

The criteria for business investment are multiple and complex. In order to simplify these relationships, it is first necessary to briefly consider the private

1. See C. Berg, "Technical Basis for Energy Conservation," *Technology Review* 76(1974): 14; U.S. Senate, Committee on Commerce, *Energy Waste and Energy Efficiency in Industrial and Commercial Activities* (Washington, D.C.: June 1974); and E. P. Gyftopoulos, et al, *Potential Fuel Effectiveness in Industry* (Cambridge, Massachusetts: Ballinger, 1974).

Table 5.1. Major Industry Groups: Age of Plant, 1975

SIC Code	Industry Group	First Year of Operations Class (%)				
		1950 and earlier	1951–1960	1961–1965	1966–1970	1971–1975
20–39	All manufacturing	57	16	9	11	7
20	Food and kindred products	65	12	8	9	6
21	Tobacco products	81	D	5	4	D
22	Textile mill products	69	8	7	10	6
23	Apparel, other textile products	47	15	12	14	12
24	Lumber and wood products	49	13	11	14	13
25	Furniture and fixtures	54	15	9	11	12
26	Paper and allied products	61	15	9	11	5
27	Printing and publishing	55	14	8	12	10
28	Chemicals, allied products	59	18	7	11	5
29	Petroleum and coal products	82	9	3	4	3
30	Rubber, miscellaneous plastics products	44	15	13	17	10
31	Leather, leather products	59	14	9	12	6
32	Stone, clay, glass products	60	16	9	9	7
33	Primary metal industries	77	10	4	6	4
34	Fabricated metal products	53	17	9	12	9
35	Machinery, except electric	55	16	8	13	8
36	Electric, electronic equipment	41	27	12	13	7
37	Transportation equipment	64	20	6	6	4
38	Instruments, related products	44	21	11	14	11
39	Miscellaneous manufacturing industries	49	D	12	15	D

D = Withheld to avoid disclosing figures for individual companies.

Source: 1975 Age of Plant File in John Gover[illegible] and Cyr Linonis, "Age of Manufacturing Plants," presented at the Joint Statistical Meetings, San Diego, California, 14–17 August 1978

119

Table 5.2. Potential Savings for 1980[a]

SIC Code	Industry	1972 Energy Use (Base Year) 10^{12} Btu/yr	1980 Energy Use with Base Year Efficiency 10^{12} Btu/yr	1980 Energy Use Assuming Attainment of Net Targets 10^{12} Btu/yr	Projected 1980 Savings through Attainment of Net Targets	
					10^{12} Btu/yr	BFOE/day[b]
20	Food and kindred products	1,047	1,195	1,052	143	62,200
22	Textile mill products	474	567	440	127	55,200
26	Paper and allied products	1,388	1,526	1,210	316	137,400
28	Chemical and allied products	3,087	4,800	4,128	672	292,200
29	Petroleum and coal products	2,993	4,007	3,527	480	208,700
32	Stone, clay, and glass products	1,462	1,753	1,478	275	119,600
33	Primary metal industries	4,246	5,167	4,690	477	207,400
34	Fabricated metal products	442	587	445	142	61,800
35	Machinery, except electric	437	707	601	106	46,100
37	Transportation equipment	414	690	580	110	47,800
	Total	15,990	20,999	18,151	2,848	1,238,400

a. In terms of total energy use.

b. Barrels fuel oil equivalent (BFOE) per day; conversion factor is 6.3×10^6 Btu per BFOE.

Source: U.S. Department of Energy, *Industrial Energy Efficiency Program, Annual Report* (Washington, D.C.: 31 March 1978).

Table 5.3. Progress toward Achieving Energy Conservation Goals

SIC Code	Industry	Percent Improvement in Energy Efficiency: Realized 1976	Percent Improvement in Energy Efficiency: Target 1980
20	Food	11	12
22	Textiles	12	22
26	Paper	9	20
28	Chemicals	10	14
29	Petroleum	10	12
32	Stone, clay, glass	8	16
33	Primary metals	4	9
34	Fabricated metals	8	24
35	Machinery	19	15
37	Transportation	13	16
	Composite average	8	13

Source: U.S. Department of Energy, *Industrial Energy Efficiency Program, Annual Report* (Washington, D.C.: 31 March 1978).

sector. Goal-setting in industry is in itself a complex process; the long-run viability of a firm may depend upon the ability of management to shift emphasis in the short run from one managerial objective to another.

The traditional private sector organizational objective is profit maximization, which is likely to be the most appropriate single goal in the long run. Yet this objective is usually constrained by other parameters, which include the maintenance of market share, the maintenance of stockholder rate of return, the maintenance of sales levels, and the minimization of risk. Alternatively, each of those constraints can become a goal in its own right, particularly in the short run. Such goal substitution would, therefore, shift profitability into the category of a parameter, requiring a stated level of profitability to satisfy stockholders or management.

Assuming a long-run criterion of profit maximization, investment decisions about the purchase of equipment for either retrofitting or process change depend upon expectations of the long-term effect of these expenditures on the cash flows of the firm. Most capital budgeting models consider the contribution

120

of a capital asset to the long-term profitability of the firm: that is, if, over the lifetime of an investment, the additional benefits outweigh the marginal costs, then the investment is deemed acceptable. Specifically, the marginal benefits of an energy-related investment may include reduction in fuel costs over time, as well as favorable changes in other input/output relationships; the marginal costs include such incremental costs to the firm as capital, operating, and maintenance charges. Both benefits and costs are adjusted for the length of time of the analysis by incorporating some version of present valuation. In view of the likelihood that, over time, both benefits and costs will vary from original expectations, assorted adjustments for decision-making under uncertainty may be incorporated into this capital budgeting framework. Analytic techniques for investment analysis are variations and extensions of this basic marginal analysis. These techniques include internal rate of return analysis, break-even analysis, payback analysis, and life-cycle costs analysis. In combination with present valuation and risk assessment theories, all of these methods allow for ranking and choosing among investment alternatives.

Despite the apparent simplicity of this general approach, numerous factors enter into the calculation of comparative feasibility; many of these variables are based upon the decision-makers' perceptions of the future. A partial list of these contributing factors include the following:

- Expected product demand
- Expected changes in the cost of capital
- Expectations of fuel cost and availability
- Interaction with regulatory requirements
- Age of existing process equipment
- Change in unit costs
- Operating and maintenance expenses
- Tax advantages
- Installation disruption

Among these factors are several influenced by external institutions. Because of the importance of these institutions to the investment decision, a brief consideration of situations in which these factors become barriers is necessary to the development of policy analysis.

III. Barriers

With respect to investment in energy conservation equipment, the term *barriers* refers to those constraints on the investment decision that are raised by the regulations, policies, or procedures of institutions in both the public and private sectors. Thus, environmental regulation would be an example of a barrier to certain fuel substitution measures. Similarly, barriers are raised by the policies of financial institutions, which offer different interest rates depending upon the purpose and the time horizon of the loan. Because the general field of energy production is highly regulated, numerous barriers are unintentionally raised by state, federal, and local power regulatory boards against private sector cogeneration when requirements originally established for commercial electrical generation are applied to generation for internal use.[2]

Reducing and avoiding such barriers are goals of policymakers. As information is a primary requisite to attaining that goal, studies are under way to identify the sources of barriers to industrial investment in conservation. A recent study by the Lawrence Berkeley Laboratory has developed a method of identifying potential barriers to investment by analyzing the interaction of attributes of various conservation measures with the characteristics of the industry.[3]

Figures 5.1 through 5.6 treat several conservation measures considered as potential investments by the steel and chemical industries. Each table is a matrix that expresses industrial sector characteristics as row variables and attributes of the conservation measure as column variables. The industrial sector characteristics are factors that have significant bearing upon the investment decision; these characteristics are described for the particular industry as of "high, medium, or low" (H, M, or L) importance. Similarly, the column variables of conservation measure attributes are rated "high, medium, or low" depending upon qualitative determination. Each cell contains a sign for plus, minus, or zero. These represent the resultant interaction of conservation measure attributes and industrial sector characteristics. Plus indicates a combination of factors that increases the likelihood of adoption. Minus denotes the decreased likelihood of the adoption of the measure, and zero denotes the lack of significant effect.[4] Examination of the matrix will determine whether the given conservation

2. G. N. Hatsopoulos, E. P. Gyftopoulos, et al. "Capital Investment to Save Energy," *Harvard Business Review* (March–April 1978).

3. Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978).

4. LBL, *Energy Conservation*, p. 11.

124

Conservation Measure Attribute / Subsector Characteristics	Cost Effective H M L	Relative Cost H M L	Unreliability Unscheduled Downtime H M L	Disruption to Install H M L	Technical Sophistication Needed H M L	Environmental Impacts + 0 −	Change in Dependency + 0 −
Market Growth H M L	0	0	0	0	0	0	0
Capital Intensity H M L	+	−,0	0	0	0	0	0
Energy Intensity H M L	+	0	0	0	0	0	0
Access to Credit H M L	0	0	0	0	0	0	0
Rate of Return on Investment H M L	0	0	0	0	0	0	0
Regulatory Restrictions H M L	0	0	0	0	0	0	0
Age of Plant (old) H M L (new)	+	−	0	0	0	0	0
Availability of Fuels H M L	0	0	0	0	0	0	0
Technical Complexity H M L	0	−	0	−	−	0	0

Figure 5.1. Conservation/investment matrix for improved housekeeping in the steel industry

Source: Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978), p. 14.

measure faces significant barriers, which might require government action.[5]

Government action is both a potential creator and a potential remover of barriers to investment. Accordingly, the following section describes a theory of optimality of government actions. The various policy measures that currently influence the decision to invest in industrial energy conservation are then briefly described in the review of existing legislation.

IV. Public Policies Affecting Energy Consumption

Energy-related public policy encompasses the group of laws, taxes, incentives, or rules by which the public sector alters the level of energy use that results from a purely private sector equilibrium. It is empha-

5. LBL, *Energy Conservation*, p. 12.

122

Conservation Measure Attribute / Subsector Characteristics	Cost Effective H M L	Relative Cost H M L	Unreliability Unscheduled Downtime H M L	Disruption to Install H M L	Technical Sophistication Needed H M L	Environmental Impacts + 0 −	Change in Dependency + 0 −
Market Growth H M L	−	−	0	0	0	0	0
Capital Intensity H M L	−	−	0	0	0	0	0
Energy Intensity H M L	+	0	0	0	0	+	0
Access to Credit H M L	+	+	0	0	0	0	0
Rate of Return on Investment H M L	−	0	0	0	0	0	0
Regulatory Restrictions H M L	−	−	−	−	−	+	0,−
Age of Plant (old) H M L (new)	+	+	0	0	0	+	0
Availability of Fuels H M L	+	0	+	0	0	+,0	+,0
Technical Complexity H M L	−	−	−	−	−	0	0

Figure 5.2. Conservation/investment matrix for new plant construction in the steel industry

Source: Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978), p. 15.

sized that, in theory, intervention occurs and is justified when conditions in the private sector do not allow for equilibrium levels of energy use, conservation, and supply deemed adequate by public bodies. Such an inefficient situation may result from imperfections in the institutions and activities associated with the internal incentives of the price system.

When the private sector solution is less than optimal, movement toward a more preferable equilibrium can be effected by policies that either (1) alter the private sector solution by making marginal changes in the price system inputs, or (2) provide a substitute for the private sector solution. In either case, the general theory of public decision-making closely parallels that of the private sector in the consideration of the incremental benefits and costs of public actions.[6] The existence of positive net benefits indicates feasibility of a policy action. The general formula for policy optimization is the present value expression,

$$\text{Net benefits} = \sum_{t=1}^{n} \frac{\Delta\text{Efficiency} + \Delta\text{Equity}}{(1+i)^n} - \sum_{t=1}^{n} \frac{\Delta\text{Costs}_g + \Delta\text{Costs}_p}{(1+i)^n}.$$

6. For a survey of benefit-cost techniques, see Alan R. Prest and Ralph Turvey, "Cost-Benefit Analysis: A Survey," *Economic Journal* (1965): 683–735.

123

Conservation Measure Attribute / Subsector Characteristics	Cost Effective H M L	Relative Cost H M L	Unreliability Unscheduled Downtime H M L	Disruption to Install H M L	Technical Sophistication Needed H M L	Environmental Impacts + 0 −	Change in Dependency + 0 −
Market Growth H M L	+,0	0	0	0,−	0	0	0
Capital Intensity H M L	+,0	0	0	0,−	0	0	0
Energy Intensity H M L	+,0	0	0	+,0	0	0	0
Access to Credit H M L	0	0	0	0	0	0	0
Rate of Return on Investment H M L	0	0	0	−	0	0	0
Regulatory Restrictions H M L	+,0	0	0	0	0	+,0	0
Age of Plant (old) H M L (new)	0,−	+,0	0	0	0	+	0
Availability of Fuels H M L	0	0	0	0	0	0	0
Technical Complexity H M L	+	−	0	−	−	0	0

Figure 5.3. Conservation/investment matrix for improved housekeeping in the chemicals industry

Source: Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978), p. 16.

where $costs_a$ and $costs_p$ represent public and private costs, and the denominators of the aggregate benefit and aggregate cost expressions indicate present valuation of the n periods of policy existence based upon a rate of time discount i.[7] A theoretical optimum is achieved when all policy prescriptions have equal net marginal yields, and system net benefits are accordingly maximized. Much like private sector criteria, adjustments are made to discount not only for time elements, but also for the relative probabilities of actualizing projected benefits and costs. This model public policy is only an idealized reflection of reality; yet, like the friction-free model of the perfectly competitive economy, it provides concepts of causality and offers a measure of efficiency to which reality can be compared.

V. Review of Existing Legislation

There are three general types of policy measures that directly affect industrial energy use: tax incentives, direct regulation, and subsidies. Existing policies of each type are listed and briefly described below.

7. Clair Wilcox and W. G. Shepard, *Public Policies Toward Business* (Homewood, Illinois: Richard D. Irwin, Inc., 1975), p. 51.

124

Conservation Measure Attribute / Subsector Characteristics	Cost Effective H M L	Relative Cost H M L	Unreliability Unscheduled Downtime H M L	Disruption to Install H M L	Technical Sophistication Needed H M L	Environmental Impacts + 0 −	Change in Dependency + 0 −
Market Growth H M L	+	+	0	0	0	0	0
Capital Intensity H M L	−	−	0	0	0,−	0	0
Energy Intensity H M L	+	0	0	0	0	+	+
Access to Credit H M L	+	+	0	0	0	0	+,0
Rate of Return on Investment H M L	+	0	0	0	0	0	0
Regulatory Restrictions H M L	−	−	0	0,−	0,−	−	0,−
Age of Plant (old) H M L (new)	−	−	0	0	0	0	0
Availability of Fuels H M L	+,−	0	0	0	0	0	0
Technical Complexity H M L	+	−	−	−	−	0	0

Figure 5.4. Conservation/investment matrix for new plant construction in the chemicals industry

Source: Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978), p. 17.

The chronological ordering of public laws (PL) underscores the acceleration of industrial conservation enactments. This list covers only federal legislation that has significant, direct or indirect impact on industrial energy use.[8]

A. 1974

1. Energy Supply and Environmental Coordination Act (PL 93-319)

This act involved conversion of power plants to coal and required several areas of study by the Federal Energy Administration (FEA) concerning restriction of export of energy-intensive goods, incentives for increased industrial recycling, and industrial energy use efficiencies.

2. Nonnuclear Energy Research and Energy Research and Development Act (PL 93-577)

This act required that "energy conservation shall be a primary consideration in the design and implementation of the federal nonnuclear energy programs."

8. The review of energy conservation legislation relies upon Doan L. Phung, "Energy Conservation Policies," unpublished manuscript, Oak Ridge Associated Universities, Institute for Energy Analysis, Oak Ridge, Tennessee, 1978; and Congressional Quarterly, Inc., *Energy Policy* (Washington, D.C.: April 1979).

125

Conservation Measure Attribute / Subsector Characteristics	Cost Effective H M L	Relative Cost H M L	Unreliability Unscheduled Downtime H M L	Disruption to Install H M L	Technical Sophistication Needed H M L	Environmental Impacts + 0 −	Change in Dependency + 0 −
Market Growth H M L	+	+	0	−	0	0	0
Capital Intensity H M L	−	+	0	−	0	0	0
Energy Intensity H M L	+	−	0	0	0	+	0
Access to Credit H M L	0	+	0	0	+	0	0
Rate of Return on Investment H M L	−	+	0	0	0	0	0
Regulatory Restrictions H M L	0,−	0,−	+,0	0	0,−	0,−	0
Age of Plant (old) H M L (new)	+,−	+	+	0,−	0	0	0
Availability of Fuels H M L	+,−	+,−	0	0	+,−	+,−	+,−
Technical Complexity H M L	−	0,−	+	−	−	0	0

Figure 5.5. Conservation/investment matrix for waste heat recovery in the chemicals industry

Source: Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978), p. 18.

B. 1975

The Energy Policy and Conservation Act (PL 94-163) required that the FEA establish efficiency targets in each of the 10 most energy-consuming sectors. The program was voluntary with no penalties for failure to reach the targets.

C. 1976

Under the Energy Conservation and Production Act (PL 94-385), the FEA was authorized to study electric utility rate design changes with respect to the effects of peak pricing, load management, etc

D. 1978

The 1978 National Energy Act is comprised of five bills, each having impact upon the industrial sector:

The Powerplant and Industrial Fuel Use Act (PL 95-620)
The Energy Tax Act (PL 95-618)
The Public Utility Regulation Policies Act (PL 95-617)
The Natural Gas Policy Act (PL 95-621)
The National Energy Conservation Policy Act (PL 95-619)

Conservation Measure Attribute / Subsector Characteristics	Cost Effective H M L	Relative Cost H M L	Unreliability Unscheduled Downtime H M L	Disruption to Install H M L	Technical Sophistication Needed H M L	Environmental Impacts + 0 −	Change in Dependency + 0 −
Market Growth H M L	+	+	0	0	0	0	0
Capital Intensity H M L	−	−	0	+,−	−	0	0
Energy Intensity H M L	+	−	0	0	0	+	0
Access to Credit H M L	−	−	0	0	0	0	0
Rate of Return on Investment H M L	0	0	0	0	0	0	0
Regulatory Restrictions H M L	−	−	+,−	0	0,−	−	0,−
Age of Plant (old) H M L (new)	+	+	0	0	0	0	0
Availability of Fuels H M L	+,−	+,−	+,−	+0−	+,−	+,−	0
Technical Complexity H M L	+	−	−	0,−	0,−	0	0

Figure 5.6. Conservation/investment matrix for process change and major renovation in the chemicals industry

Source: Lawrence Berkeley Laboratory, *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry* (Berkeley: University of California, September 1978), p. 19.

1. Powerplant and Industrial Fuel Use Act

Title II barred new electric power plants and major fuel-burning installations from using fuel oil or natural gas as the primary energy source in large boilers. The energy secretary was also empowered to issue rules prohibiting oil and gas use in broad categories of non-boiler uses. Temporary exemptions could be obtained, however, on grounds of environmental constraints or in cases of the physical incapability of conversion; provision for permanent exemption was also made.

Title III dealt with existing facilities, prohibiting the burning of natural gas after 1990; plants not using gas as a primary fuel during 1977 were prohibited from converting to gas. Title IV empowered the energy secretary to prohibit the space heating use of natural gas if the boiler consumed 300,000 cubic feet of gas per day and could run on oil. Title IV, Section 602, authorized $400 million in both 1979 and 1980 for loans to existing power plants to finance the cost of pollution control devices required for coal conver-

127

sion, and Title VII created programs to study the effects of increased coal use.

2. Energy Tax Act

A 10% investment tax credit was provided to businesses for the installation of (1) equipment for producing synthetic fuel, geothermal, solar, or wind energy if installed in a new building; (2) heat exchangers, waste heat boilers, heat wheels, recuperators, heat pipes, automatic energy control systems, and other specified items for industrial energy conservation in process uses; and (3) specified industrial recycling equipment, shale oil equipment, and equipment used to produce natural gas from geopressured brine. Moreover, the act provided special depreciation treatment for natural gas or oil boilers replaced before their expected retirement and a percentage depletion allowance for natural gas produced from geopressured brine. It also denied investment tax credit and accelerated depreciation for specified gas and oil boilers.

3. Public Utility Regulatory Policies Act

The primary effect of this act involved the impact of rate structure changes upon industrial electricity rates. These provisions required the prohibition of declining block rates and the encouragement of seasonal rates, time-of-day rates, interruptible rates, and load management techniques. Other sections of the act that affect industry are as follows:

Title II, Section 210, provided for the encouragement of cogeneration and small-scale power production by establishing rules which required utilities to sell electricity to and purchase electricity from qualifying cogenerational facilities.

Title IV encouraged industrial development agencies to develop small hydroelectric projects. Loans were made available for feasibility studies and for licensing costs.

4. Natural Gas Policy Act

A number of the provisions of this act potentially influence industrial energy use. The act required an incremental pricing rule for industrial boiler fuel facilities, which identified those low-priority gas consumers who would bear the higher costs for purposes of easing the impact on high-priority users. Furthermore, once an incrementally priced industrial facility reached gas prices equal to an alternate fuel's, the higher gas costs would be limited to the alternative fuel price level. Title IV of the act specified certain industrial processes or feedstock uses that have curtailment priorities after residences, businesses, schools, and hospitals.

5. The National Energy Conservation Policy Act

Although directed primarily at houses and businesses, this act did make provision for the establishment of industrial equipment efficiencies and recycling targets. It also provided for the testing and labeling of energy efficiencies in specified process heat, electrolytic, and electric motor-driven equipment and set targets for the use of recycled materials in the metals, paper, textile, and rubber industries.

VI. Policy Assessment

Assessment of industrial energy policy not only involves the appraisal of past and existing policy efforts but also can establish relationships upon which projection of future policy actions may be based. Policy analysis is, therefore, an ongoing process by which the gap between theory and reality can be narrowed.

Because the preponderance of existing federal conservation legislation was enacted in the fall of 1978, many associated policy directives have only recently been issued. Under these conditions, impact assessment is premature. In the absence of such appraisals, policy impact projections can only be based upon the effectiveness of parallel or general policy issues. For example, projections of the effectiveness of the industrial energy tax policies may be based upon the substantial literature which deals with the general response of industrial investment to tax policy.[9] Based on this type of response, simulations can be developed to estimate the impact of the explicit energy policy.

This chapter does not attempt to enumerate the vast number of state and local policies enacted since 1974. The relationship between these state and local policies and federal legislation does merit study, particularly because of the possible existence of conflicting as well as complementary relationships.

9. See Robert Eisner and Patrick Lawler, "Tax Policy and Investment: An Analysis of Survey Responses," *American Economic Review* 65, no. 1 (March 1975); R. E. Hall and D. W. Jorgenson, "Tax Policy and Investment Behavior," *American Economic Review* (June 1967); and G. Fromm, ed., *Tax Incentives and Capital Spending* (Washington, D.C.: The Brookings Institution, 1971).

128

Bibliography for Section I

Baughman, M. L., and Zerhoot, F. S. *Energy Consumption and Fuel Choice by Industrial Consumers in the United States*. Cambridge, Massachusetts: MIT Laboratory, March 1975.

Berg, C. A. "Technical Basis for Energy Conservation," *Technology Review* 76(1974):14–23.

California, University of, Lawrence Berkeley Laboratory. *Energy Conservation: Policy Issues and End-Use Scenarios of Savings Potential*, Part 3: *Policy Barriers and Investment Decisions in Industry*. Berkeley: University of California, September 1978; LBL 7896 pt. 3.

Congressional Quarterly, Inc., *Energy Policy*. Washington, D.C.: April 1979.

Cook, Earl. "The Flow of Energy in an Industrial Society," *Scientific American* 224, no. 3 (September 1971): 134–44.

Darmstadter, Joel; Dunkerley, Joy; and Alterman, Jack. *How Industrial Societies Use Energy: A Comparative Analysis*. Baltimore: Johns Hopkins University Press for Resources for the Future, Inc., 1977.

Dyson, Freeman J. "Energy in the Universe," *Scientific American* 224, no. 3 (September 1971).

Edmonds, James A. *A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies*. Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978; ORAU/IEA-78-15(R).

Eisner, Robert, and Lawler, Patrick. "Tax Policy and Investment: An Analysis of Survey Responses," *American Economic Review* 65, no. 1 (March 1975).

Fromm, Gary, ed. *Tax Incentives and Capital Spending*. Washington, D.C.: The Brookings Institution, 1971.

Gushee, David E. "Energy Accounting." In U.S. Library of Congress, Congressional Research Service, *Energy Accounting as a Policy Analysis Tool*. Washington, D.C.: 1976.

Gyftopoulos, E. P., et al. *Potential Fuel Effectiveness in Industry*. Cambridge, Massachusetts: Ballinger, 1974.

Hall, R. E., and Jorgenson, D. W. "Tax Policy and Investment Behavior," *American Economic Review* (June 1967).

Hannon, Bruce. "An Energy Standard of Value." *The Annals of the American Academy of Political and Social Science*, no. 410 (1973): 139–52.

Hatsopoulos, G. N.; Gyftopoulos, E. P.; et al. "Capital Investment to Save Energy," *Harvard Business Review* 56, no. 2 (March–April 1978): 111–22.

Herendeen, Robert A. "Use of Input-Output Analysis to Determine the Energy Costs of Goods and Services." In U.S. Library of Congress. Congressional Research Service, *Energy Accounting as a Policy Analysis Tool*, pp. 101–23. Washington, D.C.: 1976.

Hubbert, M. King. "Energy Resources," Chapter 8 of National Research Council, *Resources and Man*, pp. 157–242. San Francisco: W. H. Freeman and Co. for National Academy of Sciences, 1969.

_____. "The Energy Resources of the Earth," *Scientific American* 224, no. 3 (September 1971).

Kidman, R. B.; Barrett, R. J.; and Koenig, D. R. *Energy Flow Patterns for 1975*. Los Alamos, New Mexico: Los Alamos Scientific Laboratory, June 1977; LA-6770.

Krenz, Jerrold H. "Energy and the Economy: An Interrelated Perspective," *Energy* 2, no. 2 (June 1977): 115–30.

Linden, Henry R. *Perspectives on U.S. and World Energy Problems*. Chicago: Institute of Gas Technology, September 1977.

McRae, Alexander, and Dudas, Janice L., eds. *The Energy Source Book*. Germantown, Maryland: Center for Compliance Information, 1977.

National Research Council. *Alternative Energy Demand Futures to 2010*, The Report of the Demand and Conservational Panel to the Committee on Nuclear and Alternative Energy Systems (CONAES). Washington, D.C.: National Academy of Sciences, 1979.

Phung, Doan L. "Industrial Energy Conservation Policies," (unpublished manuscript). Oak Ridge, Tennessee: Oak Ridge Associated Universities, Institute for Energy Analysis, 1978.

Prest, Alan R., and Turvey, Ralph. "Cost-Benefit Analysis: A Survey," *Economic Journal* (1965): 683–735.

Starr, Chauncey. "Energy and Power," *Scientific American* 224, no. 3 (September 1971).

U.S. Department of Commerce, Bureau of the Census. *Annual Survey of Manufactures, 1976, Manufacturers' Alternative Energy Capabilities (1977–78 Heating Season)*. Washington, D.C.: 1979; M76(AS)-4.4.

_____. *1977 Census of Manufactures, Preliminary Report, Fuels and Electric Energy Consumed*. Washington, D.C.: May 1979; MC77-SR-4(P).

U.S. Department of Energy, Energy Information Administration. *Annual Report to Congress, 1977*, Vol. 3: *Statistics and Trends of Energy Supply, Demand, and Prices*. Washington, D.C.: May 1978; DOE/EIA-0036/3.

_____. *Annual Report to Congress, 1978*, Vol. 2 Washington, D.C.: 1978; DOE/EIA-0173/2.

_____. *Monthly Energy Review* (May 1979).

U.S. Energy Research and Development Administration. *Administrator's Energy Data Book*. Washington, D.C.: 1976.

U.S. Senate, Committee on Commerce. *Energy Waste and Energy Efficiency in Industrial and Commercial Activities*. Washington, D.C.: June 1974.

Wilcox, Clair, and Shepard, W. G. *Public Policies Toward Business*, 5th ed. Homewood, Illinois: Richard D. Irwin, Inc., 1975.

CAFE OR PRICE?: An Analysis of the Effects of Federal Fuel Economy Regulations and Gasoline Price on New Car MPG, 1978-89

*David L. Greene**

Following a tripling of world oil prices in 1973-74, the U.S. Congress passed the Energy Policy and Conservation Act of 1975 establishing mandatory fuel economy standards for automobiles and light trucks. Beginning at 18 MPG in 1978, the passenger car standards increased to 27.5 MPG by 1985. There has been considerable debate about the influence of the standards, as opposed to the gasoline price increases in 1973-74 and 1979-80, on new car fuel economy. Twelve years of average fuel economy data are now available for every manufacturer's domestic and imported car fleets, making possible a statistical estimation of the relative importance of standards versus fuel prices in determining new car MPG. In this paper a penalty function is formulated in which deviations from either the standard or the market equilibrium demand for fuel economy create costs for manufacturers. An equation for new car MPG is derived by minimizing the sum of quadratic penalty functions. Estimation of the model, using 15 sets of manufacturer CAFE data for 1978-89, clearly indicates that the CAFE standards were a significant constraint for many manufacturers, and were perhaps twice as important an influence as gasoline prices. A test for structural change in the model does not reject the hypothesis that the CAFE constraint had the same effect on carmakers before and after 1983.

INTRODUCTION

In 1974 the fuel economy of new U.S. passenger cars hit its lowest point in recent history: 14 miles per gallon (MPG) (Heavenrich, et al., 1984). At the same time, the Organization of Petroleum Exporting Countries exercised its new found market power by tripling world oil prices. The oil price shock, together with an oil embargo of the United States organized by

The Energy Journal, Volume 11, Number 3. All Rights Reserved.

*Oak Ridge National Laboratory, Oak Ridge, Tennessee 37831.

The views expressed in this paper are those of the author and do not necessarily represent the views of the U.S. Department of Energy or the Oak Ridge National Laboratory.

130

the Arab members of OPEC and regulation of petroleum prices within the U.S., caused gasoline supply shortages and waiting lines at gas pumps. One response to these events was the passage of the Energy Policy and Conservation Act (EPCA) of 1975 (PL 94-163), which required manufacturers to meet fuel economy targets, beginning at 18 MPG in 1978 and increasing to 27.5 MPG by 1985. Efficiency targets were also specified for light trucks. Compliance is measured by the corporate average fuel economy (CAFE) number, which is the salesweighted harmonic mean MPG of a manufacturer's products. The targets must be met for domestic and imported fleets individually or a substantial fine, $5 per car sold per 0.1 MPG of shortfall, must be paid. By exceeding the standards in some years manufacturers may offset shortfalls in other years without penalty. The intent of the automotive fuel economy standards (AFES) was to stimulate technological improvements that would increase efficiency without substantially altering the size distribution of vehicles sold (U.S.DOT, NHTSA, 1977).

By 1988, new car efficiency doubled, exceeding 28 mpg (Figure 1). Cars became about 25% lighter but maintained their interior size and carrying capacity. Horsepower to weight ratios increased despite the reduction of engine size by more than one third (Heavenrich and Murrell, 1988). More efficient technologies, such as front wheel drive and fuel injection, all but totally replaced their less energy efficient counterparts. The transition appears to have been accomplished without compromising consumer satisfaction (Greene and Liu, 1988). The direct fuel cost savings to American consumers has been put at one quarter of a trillion dollars through 1987 (Greene, Sperling, and McNutt, 1988).

Since gasoline prices increased and the standards were enacted at about the same time, the relative importance of the regulations versus the market response to higher prices is not obvious. Some have argued that the MPG improvements are the natural response of the marketplace to rising fuel prices and that the AFES have had little effect (e.g., Crandall et al., 1986), while others have claimed that the market is inherently unlikely to respond strongly to gasoline price changes (von Hippel, 1987). Those holding the former view conclude that any externalities associated with petroleum consumption are most efficiently dealt with by means of a tax on oil, not fuel economy regulation. Those who doubt the efficacy of the market argue that technology is what improves energy efficiency and that regulation is a more effective way of bringing about technical efficiency improvements. The extent to which the fuel economy standards, as opposed to gasoline prices, brought about higher efficiency is of more than academic interest because it bears on the need for, and likely effectiveness of, future fuel economy regulation.

This paper describes a statistical test of the importance of the CAFE constraint, using individual manufacturer CAFE data compiled by the National Highway Traffic Safety Administration (NHTSA) for the period 1978-89 (U.S.DOT, NHTSA, 1989). Some manufacturers, particularly Japanese manufacturers, consistently exceeded even the 1985 standard of 27.5 MPG. The existence of manufacturers for whom CAFE was no constraint, as well as

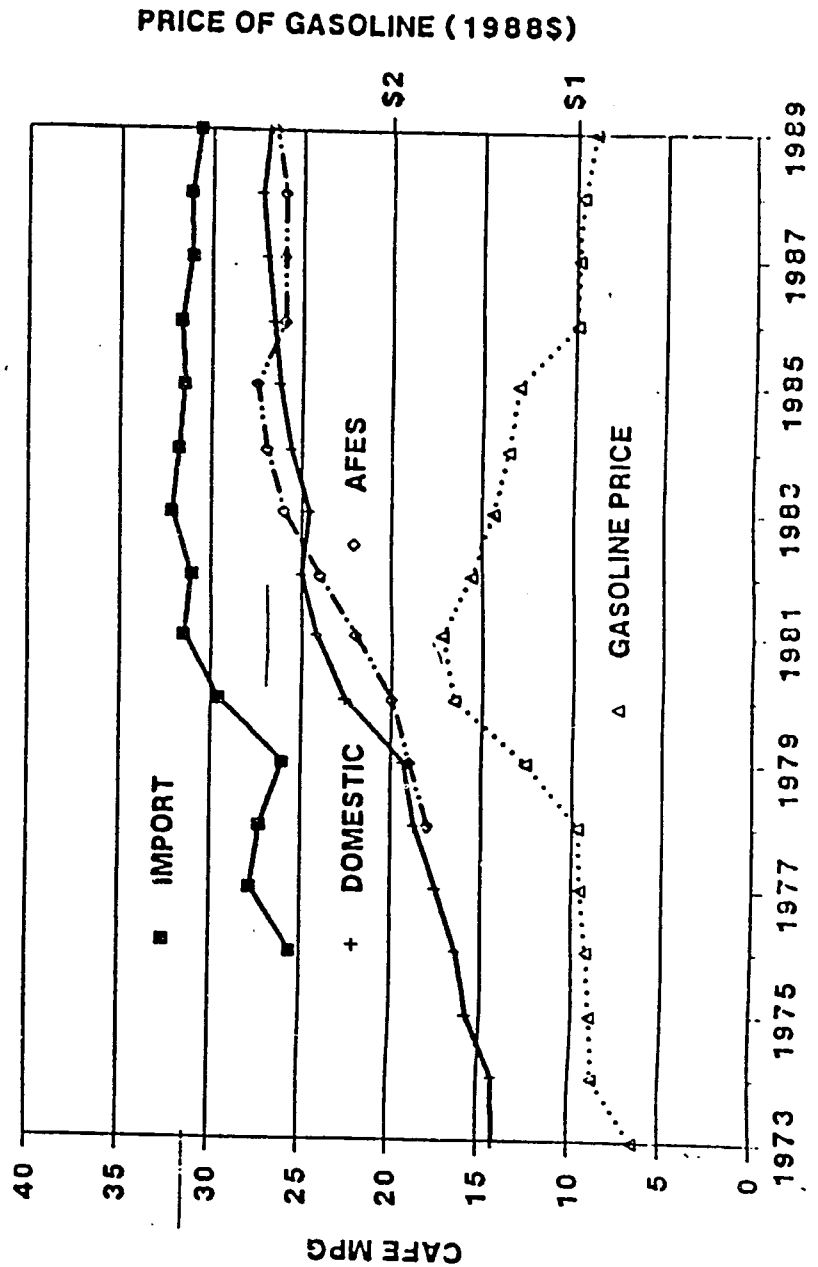


Figure 1. Trends in Fuel Price and Auto MPG, 1973-1989

those for whom it may have been a significant constraint, can be used to help discriminate between price and regulatory effects. The goals of this analysis are (1) to quantify the importance of EPCA regulations relative to gasoline prices in manufacturer decision-making about new car fuel economy, and (2) to derive an estimate of the responsiveness of new car fuel economy to gasoline price in the absence of a fuel economy constraint.

MANUFACTURER DECISION-MAKING WITH A FUEL ECONOMY CONSTRAINT

In the presence of government fuel economy regulation, the manufacturer faces the problem of balancing the need to comply with the law against the need to provide the level of fuel economy and other vehicle characteristics that the market demands. As fuel prices fluctuate, market demand for fuel efficiency should rise and fall. The federal standards may be consistent with or contrary to these market trends. Nonetheless, the automobile manufacturer must be concerned with both. Just as there are fines for failure to meet the standards, the penalty of lost profits and lost market share must be paid for being out of step with the market.

Assume that the manufacturer's objective in selecting a level of fuel economy, E, is to minimize the combined penalties of being out of step with the level of fuel economy that would maximize his profits in the absence of regulation, E_M, and the level required by regulation, E_R.

$$\text{Minimize } Z = f(E_M,E) + dg(E_R-E) \qquad (1)$$

$$d\begin{cases} = 0 \text{ if } E \geq E_R \\ = 1 \text{ if } E < E_R. \end{cases}$$

The regulatory penalty is a linear function of the difference between the MPG achieved by the manufacturer and the automotive fuel economy standard: $5 per 0.1 MPG per vehicle sold. In reality, however, the situation is more complicated. There are nonmonetary penalties as well: bad publicity and personal liability for the company's management. Furthermore, manufacturers can use credits earned by exceeding the standards in some years to offset deficits in others. Finally, they have the option of pressing for a rulemaking to lower the standard. This strategy was successful in lowering the AFES by 1 MPG or more in each of the years from 1986-89.

The penalty for being out of step with the market will depend not only on the cost of producing efficiency but also on the trade-offs between efficiency and other valued vehicle attributes and the ability of manufacturers to advance technology and change the trade-offs, as well as on input prices and consumers' preferences. Since the regulatory penalty should not affect any of these factors, it is reasonable to assume that the penalty functions are

additive, as shown in equation (1). As a second-order approximation to more complex penalty functions, f and g are assumed to be quadratic functions of the differences between the desired market (or regulatory) levels and the efficiency actually achieved.

A quadratic approximation to the manufacturer's penalty function might seem inappropriate at first.[1] The statutory penalties associated with the federal fuel economy regulations are $5 per tenth of an MPG by which the manufacturer falls short of the standard multiplied by the number of cars sold, and zero if the standard is exceeded. Thus, it would appear that the penalty function is piecewise linear and that there is no benefit at all to exceeding the standard. However, manufacturers must plan years in advance to achieve future fuel economy goals in a future market in which fuel prices, consumer preferences and competition are uncertain. The importance of this fact to understanding the role of fuel economy regulation cannot be overemphasized. Thus, there is an insurance benefit to manufacturers in planning to exceed the standards. Furthermore, the CAFE law allows manufacturers to build up credits by exceeding the standards which can be used to offset deficits in other years. This carry forward-carry back provision, together with the uncertainty manufacturers face in planning for future MPG, requires that the penalty function allow benefits for exceeding the standards as well as costs for falling short. It is also clear that the true form of the penalty function is unknown. In light of the above, the quadratic approximation is a reasonable one.

An equation for E can be derived from the first-order conditions for minimizing Z with respect to E, by solving for E.

$$dZ/dE = d/dE\{[a+b(E_M-E)+c(E_M-E)^2] + d[\alpha+\beta(E_R-E)+\tau(E_R-E)^2]\}$$

$$= -b - 2c(E_M-E) - d\beta - 2d\tau(E_R-E) = 0.$$

Solving for E gives,

$$E = (b+\beta)/2(c+\tau) + [c/(c+\tau)]E_M + [\tau/(c+\tau)]E_R \text{ , if } d = 1 \qquad (2)$$

$$= b/2c + E_M \text{ , if } d = 0 \qquad (2a)$$

or,

$$E = A + (1-B)E_M + BE_R \text{ , if } d = 1, \qquad (2b)$$

where $A = (b+\beta)/2(c+\tau)$ and $B = (\tau/(c+\tau))$.

Thus, for these simple but flexible penalty functions, the optimal new car fuel economy will be a weighted average of the optimal market level of MPG and

1. I am grateful to Jim Sweeney for his comments and insights on this point.

the CAFE requirement, when the CAFE constraint is binding, but simply a function of the market's desired fuel economy when the AFES are not binding. Equation (2) also shows that the more important the regulatory constraint is, the less important the market's desired MPG level.

Assume that the market level of fuel economy is a function of current, year t, and past gasoline prices up to a maximum lag of L years.

$$E_M = E(p_t, p_{t-1}, \ldots p_{t-L}). \tag{3}$$

In reality, E_M depends on many factors besides fuel price, but fuel price should be by far the most important factor. According to recent research, consumers form their expectations about future gasoline prices based on experience within the last three months as well as trends over the last sixteen months (EEA, Inc., 1983). Thus, L should be at least 2 to account for consumers' desired fuel economy level. The market desired fuel economy level will also depend on the types and characteristics of vehicles manufacturers produce. Manufacturers can do very little to change the technology of their product offerings (they are basically limited to pricing strategies) with less than two years advance notice. Therefore, L should be chosen based on the leadtime required for manufacturers to make significant changes in product lines. New carlines or engines require four to five years leadtime, while significant redesign of existing makes and models may require up to three years advance preparation (EEA, Inc., 1981; Ford, 1984). Thus, L=5 (six time periods) should be adequate to estimate a model combining manufacturers' and consumers' price expectations.

It is important to allow the data to determine the best form of the market efficiency equation (3). A reasonably flexible model is the polynomial distributed lag (PDL) model, in which the coefficients of the price expectation equation,

$$E_M(t) = b + b_0 p_t + b_1 p_{t-1} + \ldots + b_L p_{t-L}, \tag{4}$$

are assumed to follow a polynomial of chosen degree (Madalla, 1988, pp. 355-361). If the polynomial is quadratic, for example, then,

$$b_i = a_0 + a_1 i + a_2 i^2 . \tag{5}$$

(The a's and b's here are unrelated to those in equations (1) and (2).)

Because the lagged variables are highly correlated, equations (4) and (5) are most effectively estimated by using a smaller number of variables constructed from the p_{t-i}'s. Using equation (5), we can express $E_M(t)$ in terms of the quadratic equation coefficients,

$$E_M(t) = b + \sum_{i=0}^{L} (a_0 + a_1 i + a_2 i^2) p_{t-1}$$

p_{t-i} 2

$$= b + a_0 z_{0t} + a_1 z_{1t} + a_2 z_{2t} \tag{6}$$

where the z's are defined by,

$$z_{0t} = \sum_{i=0}^{L} p_{t-i} , \quad z_{1t} = \sum_{i=0}^{L} i p_{t-i} , \quad z_{2t} = \sum_{i=0}^{L} i^2 p_{t-L} \tag{7}$$

The lagged price coefficients, b_i, can then be calculated from the coefficients of the z_{it} using equation (5). The PDL model cannot represent all plausible price expectation models. However, it does allow the data to determine the way expectations are formed, given that fixed weights must be used.

Some manufacturers, especially Japanese manufacturers, were consistently well above the AFES requirements. In this study, any manufacturer who in year t is consistently more than one MPG above the AFES for year t+3 is considered to be unconstrained (equation 2(a) applies). For example, in 1978 the AFES was 18 MPG, and the 1981 AFES was 22 MPG. A manufacturer with a CAFE of more than 23 MPG in 1978 would be considered unconstrained in that year. If the regulatory standard is not a constraint (its penalty function is zero), the optimal level of fuel economy is the market level, E_M, plus a constant. The constant may be interpreted as a given manufacturer's deviation from the market average fuel economy and may thereby reflect a manufacturer's specialization in particular market segments.

The efficiency equation to be estimated is, therefore,

$$E_m(t) = A_m + (1-d_m B)E_M(t) + d_m B E_R(t), \tag{8}$$

where,

$$d_m \begin{cases} = 0 \text{ if manufacturer m is unconstrained and,} \\ = 1 \text{ if manufacturer m is constrained by the AFES,} \end{cases}$$

and A_m is a manufacturer-specific intercept.

Substituting equation (6) into equation (8) we get the form of the model used for estimation.

$$E_m(t) = A_m + (1-d_m B)(b_0 + a_0 z_{0t} + a_1 z_{1t} + a_2 z_{2t}) + d_m B E_R \tag{9}$$

$$= A_m^i + b_0^i + a_0^i z_{0t} + a_1^i z_{1t} + a_2^i z_{2t} + d_m B E_R$$

The superscript, i, indicates that coefficients are different for constrained

versus unconstrained manufacturers. Assuming identical E_M functions, the coefficients should differ by a constant factor, (1-B). In the estimation we do not impose this constraint, which allows constrained and unconstrained manufacturers to have different functions. This produces an interesting result, as will be seen.

The PDL formulation allows the data to dictate how past fuel prices influence new car fuel economy. Because of manufacturers' leadtime requirements, we can expect the current year and one-year lag coefficients to reflect the response of consumer demand to gasoline price changes, while longer lags reflect the manufacturers' response via new and redesigned product offerings. Current and one-year lags may also reflect manufacturers' short-term reaction to changes in the market demand for fuel economy (e.g., pricing strategies to encourage sales of more efficient car types). For the fuel economy standard, only the current year is included since the standards are generally set far enough in advance to allow manufacturers time to adjust their product offerings. Exceptions are the rulemakings in 1986-1989, which lowered the AFES on relatively short notice.

FUEL ECONOMY AND FUEL PRICE TRENDS

The general trend of automobile MPG over the past fifteen years suggests a strong relationship to the fuel economy standards. Gasoline prices rose sharply twice, declined gradually twice, and fell sharply once (Figure 1). The 1989 price of $0.96 (1988 $s) is actually below the constant dollar price in 1975. At the same time, domestic automobile MPG doubled from 14 to 28 MPG, increasing in every year except 1983. The efficiency of imported cars also increased, though less dramatically (Figure 1). These gasoline price and MPG trends certainly suggest a correlation between the fuel economy standards and the fuel economy realized, in particular, by domestic manufacturers. A closer look at individual manufacturers' CAFE numbers reveals at least three different types of patterns (NHTSA, 1989).

The CAFE MPGs of the "Big Three" domestic manufacturers (Chrysler, Ford, and General Motors) are very close to the AFES in every year (Figure 2). Each experienced a decline in fuel economy in 1983; GM and Chrysler also expect declines in 1989; Ford's CAFE slipped in 1987 and 1988. Only Chrysler consistently exceed the AFES of every year, but all three manufacturers satisfied the EPCA regulations by using credits earned by exceeding the standards some years to offset shortfalls in others (Automotive News, 1989). Certain European manufacturers' CAFE numbers exhibit the same "constrained" pattern (e.g., Volvo, Figure 3).

Other imported manufacturers were far above the 18 MPG standard in 1978 and remained well above the AFES throughout the twelve-year period (see Figure 3). For example, Volkswagen's salesweighted MPG was in excess of 27 MPG in 1978. Most of the others who fit the "unconstrained" pattern are Japanese car builders (e.g., Toyota, Nissan).

Figure 2: Corporate Average, MPG vs. Standard – Domestic Vehicles

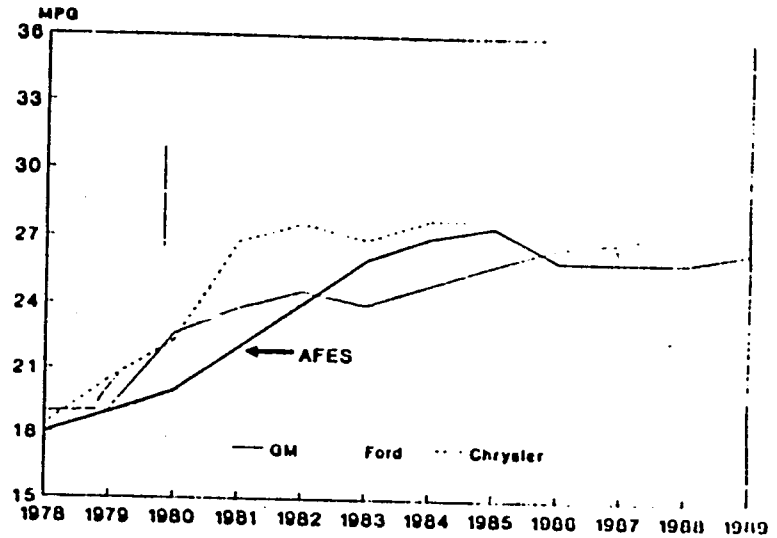
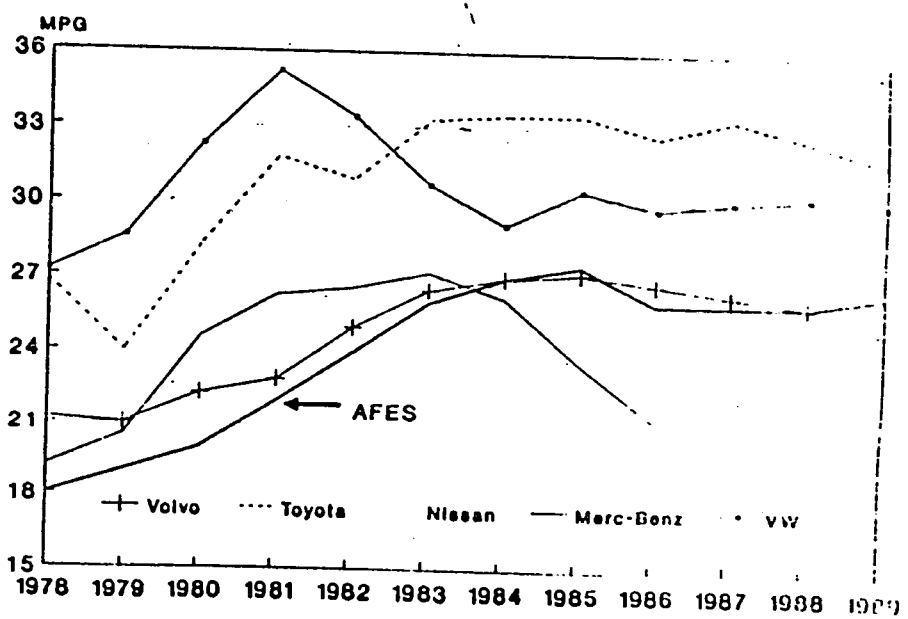


Figure 3: Corporate Average, MPG vs. Standard – Imported Vehicles



Still other importers reflect a mixed pattern. Mercedes-Benz, for example, closely followed the AFES and even exceeded them by a comfortable margin until 1984. At that point the company appears to have given up trying to meet the standards, and returned to a level of fuel economy it considered more consistent with consumer demand. Mercedes-Benz paid a $20.2 million penalty for the 1986 model year and is reportedly facing a similar fine for 1987 (Automotive News, 1989). BMW's MPG history is similar to that of Mercedes. The fact that the two manufacturers conforming to this "discouraged" pattern both sell high-priced automobiles suggests that their market segment may be less interested in fuel economy, and less sensitive to cost, than the market as a whole.

The patterns of MPG change exhibited by the "constrained," "unconstrained," and "discouraged" examples, shown in Figures 2 and 3, are typical of others. In them we see graphical evidence that the AFES do matter to producers, but also that market factors matter as well. The oil price collapse in 1986 is almost certainly a factor in Mercedes-Benz' steep drop in MPG and is probably a factor in the smaller declines experienced by other manufacturers. In the following section, these tendencies are quantified by estimating the parameters of the manufacturers' MPG decision model specified above.

The principal source of data for this analysis is the National Highway Traffic Safety Administration's official CAFE estimates (U.S. D.O.T., 1989). NHTSA compiles data for every manufacturer's domestic and imported fleet, and for light trucks as well as cars. Only the passenger car data were used in this study. Only manufacturers with a full twelve years of CAFE numbers were included. In addition, Ford's imported car line was dropped because of the lack of stability in product offerings. Until 1985 Ford imports sold only the Ford Fiesta. This changed drastically in 1985 when the Fiesta was dropped, and drastically again in 1988 when the Ford Festiva was introduced. Low-volume, high-performance, high-priced luxury cars were also excluded. This category included Alfa-Romeo, Jaguar, and Rolls-Royce (similar manufacturers, such as Ferrari and Lamborghini, did not have a full twelve years of data). The fifteen manufacturers included were: BMW, Chrysler domestic, Chrysler import, Ford domestic, GM domestic, Honda, Mazda, Mercedes-Benz, Nissan, Peugeot, Saab, Subaru, Toyota, Volvo, and Volkswagen.

Fuel price data for 1973-1989 were obtained from the Monthly Energy Review and Annual Energy Review (U.S. D.O.E., 1988, 1989). Prior to 1978 the average price of regular leaded gasoline was used because the series for the average price of all grades begins in 1978 and because the price series for unleaded regular does not begin until 1976. In 1978 and subsequent years the average of all grades was substituted. While most new cars are designed for unleaded regular, many owners buy premium, and a significant number misfuel with leaded gasoline. In any case, all of the DOE gasoline price series are highly correlated. Prices were inflated to 1988 dollars using the implicit price deflator of the Gross National Product.

THE IMPORTANCE OF MPG STANDARDS: ESTIMATION AND INFERENCE

In this section the parameters of the manufacturer's efficiency equation are estimated and several hypotheses about the structure of the equation and its stability over time are tested. First, equation (8) is estimated to determine the relative importance of fuel prices and fuel economy regulations and to infer the nature of manufacturers' responses to gasoline price increases. Next the stability of the price effect during periods of falling versus rising prices is tested. The stability of the effect of the fuel economy constraint over time is also subjected to a statistical test. Next a model is tested that implies that, given the AFES, fuel prices may have been irrelevant to the product planning of constrained manufacturers. Finally, inferences about the price elasticity of MPG are presented for unconstrained carmakers, and for the short-run effect on constrained manufacturers.

The parameters of the manufacturers' efficiency decision model (equation 8) were estimated using the least squares dummy variable (LSDV) method on the time series of cross-sectional manufacturer data. A dummy variable was included for each of the fifteen manufacturers. Ordinary least squares was the estimation technique and manufacturer data were not weighted by sales volume. Thus, Mercedes-Benz gets just as much weight as General Motors in the determination of model parameters. The LIMDEP (TM) econometric software package performed the calculations (Greene, 1986).

Results for the basic PDL model indicate that, for constrained manufacturers, the weight given the AFES is roughly twice that given the market-determined level of MPG (Table 1). The coefficient of F_R is 0.72, which implies that the market MPG weight is 0.28. In a previous study, Santini and Vyas (1988) regressed the *change* in average MPG for *all* new cars against the *change* in CAFE, a trend variable, and two price variables, and obtained a coefficient for the change in CAFE of 0.354. Given the differences in model formulation and data, the two results are not inconsistent. Most of the constructed price variables are statistically significant at the 0.05 level. An F test for all of the price variables proved that their combined effect is easily significant at the 0.01 level. The overall fit of the model to the data is reasonably good: the adjusted R^2 was 0.79.

Pattern of Response to Price Changes

The pattern of lagged price response can be computed from the coefficients of the constructed price variables in Table 1. Lagged price coefficients for the unconstrained manufacturers can be computed directly from the coefficients of z_0, z_1, and z_2 in Table 1, by using equation (5). Those for the constrained manufacturers are computed from the coefficients $z_0+z_0d_m$, $z_1+z_1d_m$, and $z_2+z_2d_m$ respectively, and dividing each by (1-0.72).

Table 1. PDL Model Estimates

Variable	Coefficient	Std. Error	t-ratio	Signf.Level
Dummy variables				
BMW	5.20	2.72	1.91	0.055
Chrysler D	6.34	2.72	2.33	0.020
Chrysler I	26.94	2.43	11.08	0.000
Ford D	4.97	2.72	1.83	0.066
GM D	4.86	2.72	1.79	0.072
Honda	26.43	2.43	10.87	0.000
Mazda	23.28	2.43	9.57	0.000
Merc-Benz	3.91	2.72	1.43	0.149
Nissan	23.98	2.43	9.86	0.000
Peugeot	6.11	2.72	2.24	0.025
Saab	5.71	2.72	2.10	0.036
Subaru	24.95	2.43	10.26	0.000
Toyota	24.60	2.43	10.12	0.000
Volvo	5.32	2.72	1.95	0.050
Volkswagen	24.17	2.43	9.94	0.000
z_0	-0.925	0.715	-1.29	0.195
z_1	1.910	0.864	2.21	0.027
z_2	-0.341	0.178	-1.91	0.054
$z_0 d_m$	3.595	1.052	3.42	0.001
$z_1 d_m$	-4.035	1.239	-3.26	0.002
$z_2 d_m$	0.660	0.249	2.65	0.009
AFES, $E_{AD} d_m$	0.719	0.085	8.43	0.000

Adjusted R^2 = 0.785 — Std. Err. of Regression = 1.94
Mean of Dependent Variable = 27.83 — Std. Err. Dep. Var. = 4.19

The division by (1-0.72) removes the assumed penalty function weight of (1-B) on the market MPG equation. In accordance with equation (8), this is necessary to obtain the price responsiveness in the absence of the AFES regulations. In the penalty function, the market-determined fuel economy level receives a weight of (1-0.72) = 0.28, so that its potential effect on new car efficiency is muted. Results presented below, however, indicate that rescaling (increasing) the constrained-carmaker price coefficients is not entirely appropriate.

Initially, one might expect the market efficiency equations for constrained and unconstrained manufacturers to be essentially the same. In fact, the estimated coefficients imply very different responses by constrained and unconstrained manufacturers to changes in the price of gasoline. According to the lagged price coefficients (Figure 4), the new car MPG of unconstrained manufacturers is determined by fuel prices of two to four years ago. This is consistent with what we know about necessary leadtimes for product development (e.g., Ford, 1984). In sharp contrast, the response of manufacturers constrained by the AFES is nearly all in the current year.

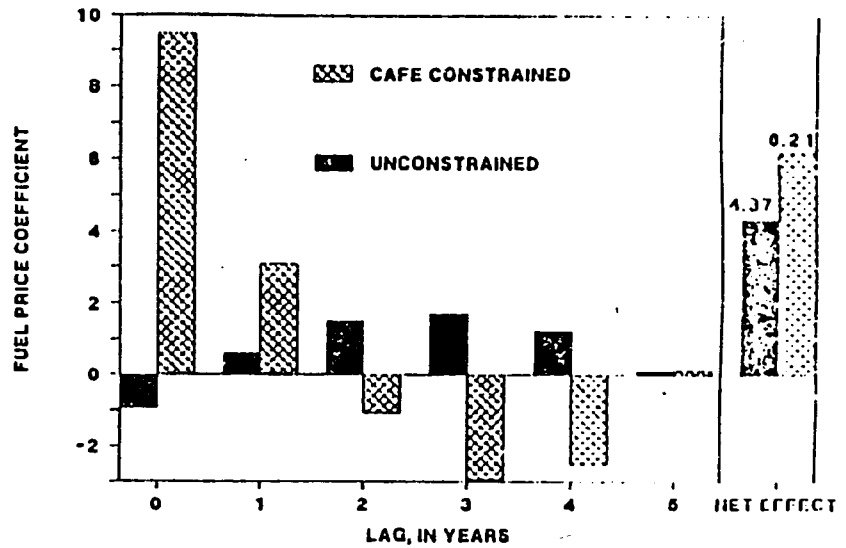


Figure 4. Lag Structure of Response to Fuel Price (by Manufacturer Relation to CAFE Constraint)

For the constrained manufacturers, product planning has been dominated by the requirement to meet the AFES goals. Thus, the potential impact of past fuel prices on research and design has been overwhelmed by planning to meet the fuel economy goals required by law. For the unconstrained manufacturers this is not the case, and their product planning has been guided by their expectations of the level of fuel economy the market would require two to four years hence.[2] If the above argument is correct, it implies that B = 1 and the level of MPG preferred by the market have not been factors in the long-run product planning of AFES-constrained car manufacturers. This

2. In fact, to some degree the fuel economy standards appear to have been a constraint on the "unconstrained" manufacturers as well. Estimations of the PDL model, as well as a simpler form discussed below, including a fuel economy standard variable for unconstrained manufacturers, produced statistically significant coefficients for that variable which were one-third to one-half the size of the CAFE constraint coefficients for "constrained" manufacturers. Other coefficients are affected very little by the inclusion of the CAFE constraint variable for "unconstrained" manufacturers. Results are available from the author. Although the federal fuel economy standards appear to have had some influence even on "unconstrained" manufacturers, the strict unconstrained definition is maintained in this paper. Strictly speaking, "unconstrained" is more properly interpreted as "mostly unconstrained" or "much less constrained." The author is grateful to Jim Sweeney for suggesting the investigation of this issue.

hypothesis is tested below and is not rejected. This, however, does not explain the lack of significance of current-year prices to unconstrained manufacturers.

Responsiveness to current year prices cannot come about by changing the engineering, design, or technology of product offerings. It is too late for such actions. It must be due to changes in the sales distribution, given the makes and models available. Thus, it must represent a consumer response, more than a manufacturer decision. In effect, it is outside of the manufacturer decision-making model presented above. When fuel prices rise, car buyers look for more efficient makes and models, raising the full-line manufacturers' average fuel economy. The constrained manufacturers' sales distributions are affected because they tend to sell a wide range of cars with differing efficiencies. The unconstrained carmakers, on the other hand, tend to sell a more limited line of efficient cars. Though they may gain market share when the current price of fuel jumps, it apparently has little effect on their sales distribution or average MPG.

The patterns of price response illustrated in Figure 4, and the above line of reasoning, suggest that a simpler formulation of the price variables may be adequate: for constrained carmakers include only the current year fuel price (P) and for unconstrained carmakers use the simple average of prices two, three, and four years ago (P2-4). Results for this simpler formulation are shown in Table 2. This formulation, which fits the data nearly as well as the complete PDL model, is more convenient for testing certain hypotheses about price effects.

Table 2. Estimated Coefficients of Simplified Model (Dummy variables omitted from table for brevity)

Variable	Coefficient	Std. Error	t-ratio	Signf. Level
P	-0.667	0.669	-1.00	0.322
PB	4.049	1.065	3.80	0.000
P2-4	4.790	1.088	4.40	0.000
$P2\text{-}4d_{m}$	-6.324	1.618	-3.91	0.000
AFES	0.728	0.086	8.49	0.000

Adj. R^2 = 0.783 Std. Err. of Regression = 1.95

Test of Linear Restrictions, P = 0, P2-4 - P2-4B = 0
$F(2, 160) = 1.318$, Signf. Level = 0.270

PB	2.851	0.717	3.98	0.000
P2-4	4.527	1.056	4.29	0.000
$P2\text{-}4d_{m}$	-4.527	1.056	-4.29	0.000
AFES	0.670	0.073	9.18	0.000

Adj. R^2 = 0.782 Std. Err. of Regression = 1.96

Stability of Price Effects

One might expect rising prices to have a different effect on new car MPG than falling prices for two reasons. First, if rising prices stimulate technological change, fuel economy will not return to its original level when price falls back to its original level. If technology has truly advanced, we would return to a somewhat higher level of MPG because better technology means we can have more MPG and more of everything else we want in a car at the same time (there is considerable empirical evidence that fuel economy technology has advanced -- see Greene, 1987; EEA, Inc., 1986; U.S. DOT, NHTSA, 1982). Thus the price coefficient for periods of rising prices would be greater than that for falling prices. Second, manufacturers can influence the salesmix in the short run by offering incentives or changing the prices of makes and models, e.g. as Kwoka (1983) has argued. But they would most likely try to shift sales only when prices were falling, to counteract the downward pressure on MPG so as to still meet the AFES targets. The effect of this would be to dampen the market response when prices are falling. Once again the coefficient for rising prices should be greater than that for falling prices.

Figure 1 suggests that the 1973 to 1989 period can be roughly divided into two parts: a period of generally increasing prices from 1973 to 1981, and a period of generally decreasing prices from 1982 to 1989. If we allow for a two-year lag for expectations to change, we have a period of rising prices from 1973-82, and falling prices afterwards. A test of price responsiveness for these two periods does indicate different modes of response. The current-year price response for domestic manufacturers appears to be about twice as large during the period of rising prices (2.5 vs. 1.2, Table 3). For unconstrained manufacturers the price coefficients are much closer in value (3.4 vs. 4.1) but there is a statistically significant increase in price sensitivity for the post 1982 period. Recall that these are predominantly Japanese manufacturers of efficient automobiles. It appears that they may have reduced their MPG in response to falling prices in the 1980s more than they increased it in response to rising prices of the 1970s. If the intent of the EPCA was to bring about roughly equal improvements by all manufacturers, this is a disturbing result. It suggests that "market slackness" created when the AFES kept constrained carmakers from fully following market trends was taken up by the unconstrained carmakers, who took the opportunity to sell a mix of less efficient cars than they otherwise would have. This evidence lends somesupport to Kleit's (1987) assertion that fuel economy regulations create economies of scope that encourage all manufacturers to become full-line manufacturers.

Table 3. Test of Equality of Price Coefficients, 1978-1982, and 1983-1989 (Dummy variables omitted from table)

Variable	Coefficient	Std. Error	t-ratio	Signf. Level
PB	2.506	0.729	3.44	0.001
PB,83	-1.281	0.701	-1.83	0.066
P2-4	3.391	1.148	2.95	0.004
P2-4,83	0.701	0.304	2.30	0.021
AFES	0.857	0.125	6.86	0.000

Adj. R^2 = .790 Std. Err. of Regression = 1.92

Stability of the AFES Constraint Effect

It has been suggested that,

> "The CAFE standards appear to have provided little but nuisance value until recently. As gasoline prices have fallen in real terms, the standards have become a binding constraint upon producers attempting to satisfy the demand for larger cars." (Crandall, et al., 1986, p. 139)

A look at Figure 1 shows that real gasoline prices stabilized in 1981 and began falling in 1982. If it is true that consumers base their price expectations on what has occurred in the past year and a half, by 1983 they should have decided that prices were headed downward. A Chow test was performed to evaluate the hypothesis that the effect of the CAFE standards in 1982 and before differed from their effect in 1983 and afterwards. The more flexible PDL model was re-estimated with separate AFES coefficients for the two time periods. As before, the AFES applies only to constrained manufacturers.

Not only can we not reject the hypothesis of equal effects before and after 1983, but the independently estimated coefficients are nearly exactly the same: 0.77 for pre-1983, and 0.75 for 1983 and after (Table 4). The F statistic for the null hypothesis that the two coefficients are identical is F = 0.124 with (1, 157) degrees of freedom, which has a significance level of 0.72. There is no evidence here to support the assertion that the automotive fuel economy standards were not binding on manufacturers prior to 1983. On the contrary, it appears that their effect has been strong and consistent throughout the entire period.

Table 4. Test of Equality of AFES Coefficients, 1978-1982 and 1983-1989 (Dummy variables omitted from table)

Variable	Coefficient	Std. Error	t-ratio	Signf. Level
z_0	-0.925	0.717	-1.29	0.196
z_1	1.910	0.866	2.205	0.027
z_2	-0.341	0.178	-1.91	0.055
$z_0 d_m$	3.334	1.290	2.57	0.010
$z_1 d_m$	-3.846	1.354	-2.84	0.005
$z_2 d_m$	0.635	0.260	2.44	0.015
AFES<83	0.770	0.168	4.57	0.000
AFES>82	0.749	0.122	6.13	0.000

Adj. R^2 = .784 Std. Err. of Regression = 1.95

Test of Equality of AFES Coefficients
$F(1, 157)$ = 0.124 Significance Level = 0.724

z_0	-0.925	0.717	-1.29	0.196
z_1	1.910	0.866	2.205	0.027
z_2	-0.341	0.178	-1.91	0.055
$z_0 d_m$	3.595	1.055	3.41	0.001
$z_1 d_m$	-4.035	1.242	-3.25	0.002
$z_2 d_m$	0.660	0.250	2.64	0.007
AFES<83	0.719	0.086	8.40	0.000
AFES<83	0.719	0.086	8.40	0.000

Adj. R^2 = 0.785 Std. Err. of Regression = 1.94

Dominance of the AFES over Fuel Prices

If the MPG of CAFE-constrained carmakers responds only to current year fuel prices, then the coefficients of their PDL price variables should be zero and the coefficient of the fuel economy standard variable, E_R, should equal 1. We now test this hypothesis, taking into account the different response of constrained carmakers to prices during the 1978-82 and 1983-89 periods. In the results presented in Table 5 the z_i-variables are defined as in equation (5) for unconstrained carmakers, and are zero otherwise. The $z_i d_m$ variables represent the PDL price variables for the constrained manufacturers. Prior to imposing the price and standard constraints, none of the price variables for constrained manufacturers is statistically significant. Jointly imposing the four constraints results in F(4, 156) = 0.553, which has a significance level of 0.70, so that we do not reject the hypothesis that B = 1. The implication is that the long-range fuel economy planning of constrained manufacturers may have been entirely dominated by the CAFE standards.

Table 5. Test of Irrelevance of Gasoline Price to Constrained Manufacturer MPG (Dummy variables omitted from table)

Variable	Coefficient	Std. Error	t-ratio	Signf. Level
z_0	-0.925	0.718	-1.29	0.196
z_1	1.910	0.867	2.20	0.027
z_2	-0.341	0.179	-1.91	0.055
$z_0 d_m$	4.908	5.351	0.92	0.364
$z_1 d_m$	-3.649	4.026	-0.91	0.370
$z_2 d_m$	0.553	0.628	0.88	0.384
PB	-3.218	6.372	-0.50	0.620
PB,83	-0.215	1.335	-0.16	0.847
AFES, $E_R d_m$	0.716	0.199	3.60	0.000

Adj. R = 0.784 Std. Err. of Regression = 1.95

Test of Linear Restrictions $z_0 d_m = z_1 d_m = z_2 d_m = 0$, AFES = 1.0

F (4, 156) = 0.553 Significance Level = 0.700

z_0	-0.925	0.718	-1.29	0.196
z_1	1.910	0.867	2.20	0.027
z_2	-0.341	0.179	-1.91	0.055
$z_0 d_m$	0.0			
$z_1 d_m$	0.0			
$z_2 d_m$	0.0			
PB	2.575	0.738	3.49	0.001
PB,83	-1.938	0.409	-4.74	0.000
AFES, $E_R d_m$	1.0			

Adj. R^2 = 0.786 Std. Err. of Regression = 1.94

Estimates of Price Elasticity of MPG

Overall price elasticities can be computed either from the net effect of the lagged price responses shown in Figure 4, or from the coefficients of current and average prices 2-4 years ago in the simplified model. Note that the elasticities computed for constrained manufacturers assume the existence of fuel economy standards. One could try to infer elasticities that one would obtain in the absence of regulation by dividing by (1-B), but given the effect that regulation appears to have on the nature of the price response, this would give misleading results. The average price of gasoline for the 1978-89 period was $1.36 per gallon and the average CAFE of all the manufacturers was 27.83 MPG. Using these values to compute elasticities of MPG with respect to a step increase in gasoline price gives,

(6.21•0.28)•(1.36/27.83) = 0.08	constrained, PDL model
2.51•(1.36/27.83) = 0.12	constrained, 1978-82
(2.51-1.28)•(1.36/27.83) = 0.06	constrained, 1983-89
4.37•(1.36/27.83) = 0.21	unconstrained, PDL model
3.39•(1.36/27.83) = 0.17	unconstrained, 1978-82
4.09•(1.36/27.83) = 0.20	unconstrained, 1983-89

The price elasticity of MPG with respect to fuel price for unconstrained manufacturers is quite small. At a long-run elasticity of 0.21, fuel prices would have to increase from $1.36 to $2.15 per gallon to bring about a 10% increase in MPG. The impact of current fuel prices on constrained manufacturers is larger during the 1978-82 period of generally rising prices than during the 1983-89 period when prices were falling. This is consistent with the idea that manufacturers may take actions to resist downward pressure on their CAFE when fuel prices are falling in order to avoid violating the AFES.

Unfortunately, the above estimates cannot be interpreted as the long-run and short-run gasoline price elasticities of MPG for the entire market. The two market segments (constrained and unconstrained) are quite different and appear to respond differently to price changes. We were not able to estimate a market MPG equation as a function of past fuel prices for constrained manufacturers, apparently because the AFES constraint was binding. Their inherent responsiveness in the absence of fuel economy regulation might have been greater or less than that of the unconstrained manufacturers. In addition, the model is designed to represent the fuel economy of individual manufacturers, and thus does not address the question of market MPG improvement via shifts in sales from less to more efficient manufacturers, and vice versa. Such sales shifts are an important component of the short-run gasoline price elasticity of MPG.

CONCLUSIONS

The automotive fuel economy standards (AFES) specified by the Energy Policy and Conservation Act of 1975 and rulemakings of the Department of Transportation, appear to have had a powerful effect on the product planning decisions of the manufacturers constrained by them. This includes all the "big three" domestic manufacturers and several European carmakers as well. The statistical analysis described here indicates that the standards were at least twice as important as market trends in fuel prices, and may have completely replaced fuel price trends as a basis for long-range planning about MPG. Of course, correlation is not causality. The possibility remains that the standards were such an accurate prediction of the future

behaviour of certain manufacturers that even the relatively flexible gasoline price model used here cannot fit the data as well. This must be considered highly unlikely since the AFES are at least predetermined, and because a clear causal mechanism, compliance with the law and civil penalties, exists.

Tests of the model structure indicate that the average MPG of constrained and unconstrained carmakers responded very differently to price changes over the 1973-1989 period. The unconstrained carmakers' current-year CAFE was affected by prices two to four years old. This is consistent with the leadtime required to make engineering and design changes in product offerings. However, the elasticity of MPG with respect to fuel price was relatively small: about 0.2. Constrained manufacturers' CAFE, in contrast, was affected only by current-year prices. This effect, no doubt, combines market demand changes with carmaker pricing and incentives strategies, since technological changes cannot be made instantaneously. This elasticity is even smaller: about 0.1.

The effect of gasoline price on MPG was different during the period of falling prices in the 1980s from its effect during the period of rising prices in the 1970s. Constrained-carmaker MPG was twice as sensitive to rising prices as falling prices, suggesting that manufacturers took some actions to counteract the downward pressure of falling prices in order to meet the AFES targets. Unconstrained manufacturers, in contrast, responded slightly more to falling than to rising prices. It may be that the effects of falling prices on constrained carmakers gave the unconstrained carmakers an opportunity to expand into lower MPG market segments.

However, there was no difference in the effect of the CAFE constraint during the two time periods. The estimated weights for the AFES before 1983 and after 1982 were 0.77 and 0.75, respectively. There was no statistical support for rejecting the hypothesis that the effects were identical.

A joint test of the hypotheses that: 1) past fuel prices were not a factor in determining the MPG of constrained manufacturers, and 2) the weight of the AFES is 1.0 (only the AFES matters), could not be rejected. That is, the data are not inconsistent with the hypothesis that constrained manufacturers based their MPG product planning solely on the mandated fuel economy standards.

These results support the assertion that the EPCA CAFE standards were effective in influencing many carmakers to plan for and achieve dramatic increases in new car fuel economy.

REFERENCES

Automotive News (1989). "Imports fear higher CAFE would boost fines, lower sales." *Automotive News*. Detroit, MI (May 1): 26.

Crandall, R. W., H. K. Gruenspecht, T. E. Keeler and L. B. Lave (1986). *Regulating the Automobile*. Washington, DC: The Brookings Institution.

Energy and Environmental Analysis, Inc. (1986). "Analysis of the Capabilities of Domestic Auto-Manufacturers to Improve Corporate Average Fuel Economy." Prepared for the Office of Policy Integration, Office of Policy, Planning, and Analysis, U.S. Department of Energy. DOE/RL/01830-111. Washington, DC (April).

Energy and Environmental Analysis, Inc. (1983). "Consumer Expectations for Future Gasoline Prices." U.S. Dept. of Energy. DE-AC01-80PE-11972. Arlington, VA (May).

Energy and Environmental Analysis, Inc. (1981). "The Technology/Cost Segment Model Post-1985 Automotive Fuel Economy Analysis." Prepared for U.S. Dept. of Energy, Office of Conservation. DE-AC01-79PE-70032. Arlington, VA (November 7).

Ford, A. (1984). "Uncertainty in the Price of Gasoline and the Automobile Manufacturers' 1981 Retooling Decision." *Energy* 9(6): 519-540.

Greene, D. L. (1987). "Advances in Automobile Technology and the Market for Fuel Efficiency 1978-1985." Transportation Research Record 1155. 18-27. Washington, DC: Transportation Research Board, National Research Council.

Greene, D. L., D. Sperling and B. McNutt (1988). "Transportation Energy to the Year 2020." In *A Look Ahead: Year 2020*. Special Report 220. Washington, DC: Transportation Research Board, National Research Council.

Greene, D. L. and J. T. Liu (1988). "Automotive fuel Economy Improvements and Consumers' Surplus." *Transportation Research Record, A*. 22A(3): 203-218.

Greene, W. H. (1986). "LIMDEP™ User's Manual." New York (May).

Heavenrich, R. M. and J. D. Murrell (1988). "Light-Duty Automotive Technology and Fuel Economy Trends Through 1988." U.S. Environmental Protection Agency Technical Report EPA/AA/OCTAB-88-07. Ann Arbor, MI (June).

Heavenrich, R. M., J. D. Murrell, J. P. Cheng and S. L. Loos (1984). "Passenger Car Fuel Economy...Trends Through 1984." Society of Automotive Engineers. SAE Technical Paper Series 840499. Warrendale, PA (February).

Kleit, A. N. (1987). "The Impact of Automobile Fuel Economy Standards." Mimeograph. Department of Economics, Yale University. New Haven, CT.

Kwoka, J. E. (1983). "The Limits of Market-Oriented Regulatory Techniques: The Case of Automotive fuel Economy." *The Quarterly Journal of Economics* 98(4): 695-704.

Madalla, G. S. (1988). *Introduction to Econometrics*. New York: MacMillan Publishing Co.

Santini, D. J. and A. D. Vyas (1988). "Theoretical Basis and Parameter Estimates for the Minority Transportation Expenditure Model (MITRAM)." Center for Transportation Research, Argonne National Laboratory. ANL/ES-159. Argonne, IL.

U.S. Department of Energy, Energy Information Administration, 1989 (1988). "Monthly Energy Review." DOE/EIA-0035(88/12). Washington, DC (December).

U.S. Department of Energy, Energy Information Administration, 1989 (1988). "Annual Energy Review 1987." DOE/EIA-0384(87). Washington, DC (May).

U.S. Department of Transportation, National Highway Traffic Safety Administration, 1977 (1977). "Passenger Automobile Average fuel Economy Standards, Final Rule." Federal Register, Part VII. (Thursday, June 30).

U.S. Department of Transportation, National Highway Traffic Safety Administration, 1982 (1982). "Automotive Fuel Economy Program: Sixth Annual Report to Congress." Washington, DC (January).

U.S. Department of Transportation, National Highway Traffic Safety Administration, 1989 (1989). "Summary of Fuel Economy Performance Estimated on a Year to Year Basis Comparing Grouped Vehicle Fleets and Manufacturers' Individual Fleets." Mimeograph, courtesy of Mr. George Entwistle. NHTSA, NEF-31. Washington, DC (February 1).

von Hippel, F. (1987). "Automobile Fuel Economy." Energy 12(10/11): 1063-1071.

NATIONS UNIES | ОБЪЕДИНЕННЫЕ НАЦИИ | UNITED NATIONS

COMMISSION ECONOMIQUE POUR L'EUROPE | ЭКОНОМИЧЕСКАЯ КОМИССИЯ ДЛЯ ЕВРОПЫ | ECONOMIC COMMISSION FOR EUROPE

SEMINAIRE | СЕМИНАР | SEMINAR

COMMITTEE ON ELECTRIC POWER

Seminar on the Rational Use of Electricity
Iassi-Moldavia (Romania), 6-8 November 1990

RESTRICTED

EP/SEM.15/R.14

ENGLISH ONLY

EVOLUTION AND STRUCTURE OF POWER CONSUMPTIONS IN THE MAIN INDUSTRIAL SECTORS

(Transmitted by the Government of Romania)

Romania's power consumption evolution in the post-war period was mainly characterized by two different stages(the state-of-the-ar being valid on a wider plan).

Within the first stage which lasted until the beginning of th '70s, energy consumption increasing rate was higher than that of the national income. It is in that period that the country's industrialization has been ordered, a strategic objective of the former country leadership commanded out of economical and political reasons.The energy intensive branches of the national economy were widely promoted. A favourable aspect was the energy excess available within that period in our country; mention should be made that during the '70s, Romania kept being an oil exporter country.The low oil price on the world market was one of the factors which made its contribution to an energy-intensive development. Power consumption was not consider an important criterion in setting up economical development strategies or in choosing certain technologies. The main issue which Rome

1/ Prepared by Mr. Vasile Rugina, Ministry of Electric Energy-DPD, Romania.

2/ The reproduction of this document has been undertaken by the transmitting Government. The paper is distributed as received.

141

nian power specialists working in research, design and operation fields had to overcome was to provide a higher reliability to the energy supply.

The average rates of increasing the national income, the overall industrial production and the primary energy consumption are shown in table 1, in percentages.

TABLE 1

	1956 1960	1960 1965	1965 1970	1970 1975	1975 1980	1980 1987
National income	6.9	9	7.7	11.2	7.0	6.6
Industrial production	8.9	13.9	11.9	12.9	9.8	5.5
Energy consumption	7.2	9.9	9.1	4.8	3.1	2.0

SOURCE: Romania's statistic annual

The second stage practically started up simultaneously with the first oil shock and was closely connected to it. Unfortunately, it during the same period that Romania changed from an exporter country into an oil and primary energy importer country. Inner crude oil and natural gas ores cutting down tendency made its contribution to the country's decline on the one hand, and the strong development of petrochemical industry requiring large quantities of raw materials on the other hand.

Table 2 shows the evolution of inner fuel production within the last 30 years.

TABLE 2

	Measuring unities	1965	1970	1975	1980	1987
Extracted crude oil	10^3 tons	12571	13377	14590	12323	9504
Pit gas	10^6 m^3	13038	19971	27001	27189	25301
Net coal from which:	10^3 t	10291	20531	27091	32764	51524
bituminous coal	10^3 t	4658	6402	7320	8108	9099
brown coal	10^3 t	569	668	616	661	846
lignite	10^3 t	5064	13461		24055	41579

SOURCE : Romania's statistic annual

Oil crisis influence had an impact in our country as well. Th specialists had to further on face the industrialization policy (whi has remained the main inner strategy) within the conditions of restri ing the access to energy sources. In order to meet this aim, the

142

concerns of energy conservation in industry have been enhanced. The obsolete technologies in energy intensive industrial branches have been given up and new and updated technologies with low energy consumptions have been implemented. Cement and steel industries will be mentioned below in order to prove the above mentioned statement.

Thus, the cement industry gave up the wet manufacturing proce and the dry process has been generalized, as shown in table 3.

TABLE 3

	Measuring unity	1965	1975	1980	1989
Cement production: from which :	10^3 tons	5583	12019	15611	13122
- dry process	%	10.9	58.6	71.4	86.6
- wet process	%	89.1	41.4	28.6	13.4

At the same time, efforts have been made in view of cutting down energy specific consumptions (i.e. cutting down particularly the fuel meant fot clinker manufacturing) for both technologies. The unitery capacity of clinker furnaces has increased according to the dry procedure from 800 t/day to 3000 t/day, as well as the clinker heat recovery degree. Therefore, fuel specific consumptions meant for getting the clinker have favourably developed as shown in table 4.

TABLE 4

	Measuring unity	1965	1975	1980	1989
Wet procedure	kJ/kg	7170	6780	6550	6295
Dry procedure	kJ/kg	6220	4100	3980	3710
Average specific consumption	kJ/kg	7020	5210	4825	4065

The iron and steel industry has witnessed a decrease of the Siemens Martin procedure share for steel production, simultaneously with the increase of the converter steel share. Table 5 shows the process :

TABLE 5

	Measuring unity	1965	1975	1980	1987
Steel production from which:	10^3 tons	3426	9549	13175	13885
-Siemens Martin	%	91.8	49.9	36.7	30.0
-converter	%	-	37.4	43.6	46.1
electrical	%	8.2	12.7	19.7	23.9

Such examples can be mentioned in other branches as well.

An important contribution for meeting this favourable development proper to the previous decade (available, to a certain extent, at present as well) was made by several technology imports carried out in the respective period.

After 1980 the economic situation further on changed, two factors making their important contribution to this.

On the one hand, the second oil shock changed the conditions on the energy international market, pointing out the already availab difficulties in the country.

On the other hand, the overall and rapid payment of external debts became a highly important political target for the country's leadership of that period.

New issues have occurred which could not be always successfull solved up.

The hopes related to the energy internal production enhancening have failed and the plan figures have not been met. Thus, an oil production of 12.500 million tons was planned for 1985, but only 10.5 million tons were extracted. A lignite production of 75 milion tons was planned, but only 37.1 milion tons were achieved. The unave lability of free currency have weakened the connections with the world market bringing about negative effects both with respect to th supply of energy resources and with respect to industrial technologies retrofitting (and not only the industrial ones). At the same time the industrialization developed within the conditions of planne economy kept its strategic objective character from the economical and political viewpoint.

Under these circumstances, during 1980 - 1987 the primary ene gy consumption at the national level increased with 14.7% (respectively from 2.79 . 10^{18} J to 3.13 . 10^{18} j). However, important changes occured with respect to the structure of this consumption according to the national economy branches. These changes are shown in table 6 - in percentages

TABLE 6

	1980	1987
OVERALL CONSUMPTION	100	100
from which		
- industry	68.9	74.2
- agriculture	4.6	3.8

144

	1980	1987
- household consumption	10.5	9.0
- transportation	5.1	3.3
- public administration	1.2	0.8
- buildings	2.6	2.1

As a matter of fact, during the analysed period, energy consumption share in industry increased both with respect to the overal consumption and to the absolute values. Energy consumption in the other branches (consumption meant for population being included) decreased both with respect to its share and to its absolute value (although the inhabitants number increased with 3.3% during that period). Such a policy has led to important economical and social strains.

Considering the development of electrical energy consumption, the situation is not qualitatively changed . During 1980-1987 electrical energy consumption at the national level increased from 67.4 TWh to 75.2 TWh (therefore with 18.6%). The consumers within all economic branches could be hardly supplied with electrical energy during that period. However, the general phenomenon known as "energy electrification" occured in our country as well. Electrical energy consumption witnessed a higher increase as compared to the primary energy consumption. The consumption structure on various branches developed as shown below, in table 7.

TABLE 7

	1980	1987
OVERALL CONSUMPTION	100	100
from which :		
-industry (including the own consumption of electrical power station)	78.3	79.5
- agriculture	4.4	5.2
- household consumption	7.5	6.4
- transportation	3.0	3.4
- public administration	1.8	1.8
- buildings	2.4	2.0

There follows that the industrial consumption share whose level is already high, kept on increasing, reaching at almost [illegible]% of the overall consumption.

145

A certain share increase in the overall consumption has been also recorded in agriculture and transportations - due to the need of increasing the technical level of these branches. The category which witnessed the highest consumption regress (both as share and as absolute values) is the population. The previous conclusion on the effects of energy supply for industry to the prejudice of population (i.e. important social stresses were gathered up) remains valid.

Several data will be further on shown concerning electrical energy consumption in industry. The synthetic data are shown in table 8 :

TABLE 8

	1980	1987
Total Industry	100	100
1. electrical and thermal energy generation	13.8	14.0
2. fuel	16.9	9.5
3. ferrous metalurgy	12.1	14.1
4. nonferrous metalurgy	12.0	10.4
5. machine building	12.7	13.5
6. chemistry	22.1	20.1
7. building materials	5.5	4.6
8. light industry	3.8	3.3
9. food industry	2.8	2.9

The increase of inner consumption share of thermal power stations and of the fuel branch can be easily explained by technical reasons. Low heat power lignite burning in thermal power stations brings about higher consumptions. Similarly, the worsening of fuel operating conditions leads to an important increase of the energy consumptions implied in this operation.

The large energy consuming branches in the Romanian industry were and kept being the metalurgic industry (ferrous and nonferrous) and the chemical industry, both of them consuming almost half of electrical energy amount supposed for the whole industry (46.3% in 1980 and 44.6% in 1987). Unfortunately, these values do not meet the shares of these branches with respect to the industrial production value achieved at a national level, shares which, in 1980 had the following values :

- ferrous metalurgy : 7.4%
- nonferrous metalurgy : 3.2%
- chemistry : 8.7%

The light, food and consumption assets production industries have, each on turn or all together, a relatively reduced share in the electrical energy consumption, a share which has sharply decreas in the light industry. This decrease has been entailed both by the production decrease - at a certain basic products - within the analys period.(flax, hemp and mixed fibres at 41.6 thousands tons, woolen fibres from 77.6 thousands tons to 75.9 thousands tons, cotton fibres from 187 tgousands tons to 172 thousands tons, knit goods from 336 milion pieces to 275 milion pieces etc).

Mention should be made that from the valoric considerations , these branches highly make their contribution at the overall industrial production (light industry with 14%, food industry with 12.8% in 198o).

It may be presently estimated that primary energy and electrical energy consumption are quite disproportional (i.e. an exagerated consumption share in industry and particularly in the metalurgical and chemical industries) and have a small share of other branches (household consumption, agriculture, transportations). These structures are due to the the previously promoted political factors of the respective period. As far as a market economy is promoted in Romania, the energy consumption structure is likely to be correspondingly changed.

NATIONS UNIES | ОБЪЕДИНЕННЫЕ НАЦИИ | UNITED NATIONS

COMMISSION ECONOMIQUE POUR L'EUROPE | ЭКОНОМИЧЕСКАЯ КОМИССИЯ ДЛЯ ЕВРОПЫ | ECONOMIC COMMISSION FOR EUROPE

SEMINAIRE | СЕМИНАР | SEMINAR

COMMITTEE ON ELECTRIC POWER

Seminar on the Rational Use of Electricity
Iassi-Moldavia (Romania), 6-8 November 1990

RESTRICTED

EP/SEM.15/R.14

ENGLISH ONLY

EVOLUTION AND STRUCTURE OF POWER CONSUMPTIONS IN THE MAIN INDUSTRIAL SECTORS

(Transmitted by the Government of Romania)

Romania's power consumption evolution in the post-war period was mainly characterized by two different stages(the state-of-the-ar being valid on a wider plan).

Within the first stage which lasted until the beginning of th '7o^{s}, energy consumption increasing rate was higher than that of the national income. It is in that period that the country's industrialization has been ordered, a strategic objective of the former country leadership commanded out of economical and political reasons.The energy intensive branches of the national economy were widely promoted. A favourable aspect was the energy excess available within that period in our country; mention should be made that during the '7o^{s}, Romania kept being an oil exporter country.The low oil price on the world market was one of the factors which made its contribution to an energy-intensive development. Power consumption was not consider an important criterion in setting up economical development strategies or in choosing certain technologies. The main issue which Roma

1/ Prepared by Mr. Vasile Rugina, Ministry of Electric Energy-DPD, Romania.

2/ The reproduction of this document has been undertaken by the transmitting Government. The paper is distributed as received.

nian power specialists working in research, design and operation fields had to overcome was to provide a higher reliability to the energy supply.

The average rates of increasing the national income, the overall industrial production and the primary energy consumption are shown in table 1, in percentages.

TABLE 1

	1956 1960	1960 1965	1965 1970	1970 1975	1975 1980	1980 1987
National income	6.9	9	7.7	11.2	7.0	6.6
Industrial production	8.9	13.9	11.9	12.9	9.8	5.5
Energy consumption	7.2	9.9	9.1	4.8	3.1	2.0

SOURCE: Romania's statistic annual

The second stage practically started up simultaneously with the first oil shock and was closely connected to it. Unfortunately, it during the same period that Romania changed from an exporter country into an oil and primary energy importer country. Inner crude oil and natural gas ores cutting down tendency made its contribution to the country's decline on the one hand, and the strong development of petrochemical industry requiring large quantities of raw materials on the other hand.

Table 2 shows the evolution of inner fuel production within the last 30 years.

TABLE 2

	Measuring unities	1965	1970	1975	1980	1987
Extracted crude oil	10^3 tons	12571	13377	14590	12523	9504
Pit gas	10^6 m^3	13038	19971	27001	27189	25301
Net coal from which:	10^3 t	10291	20531	27091	32764	51524
bituminous coal	10^3 t	4658	6402	7320	8108	9099
brown coal	10^3 t	569	668	616	661	846
lignite	10^3 t	5064	13461		24055	41579

SOURCE : Romania's statistic annual

Oil crisis influence had an impact in our country as well. Th specialists had to further on face the industrialization policy (whi has remained the main inner strategy) within the conditions of restri ing the access to energy sources. In order to meet this aim, the

149

concerns of energy conservation in industry have been enhanced. The obsolete technologies in energy intensive industrial branches have been given up and new and updated technologies with low energy consumptions have been implemented. Cement and steel industries will be mentioned below in order to prove the above mentioned statement.

Thus, the cement industry gave up the wet manufacturing proce and the dry process has been generalized, as shown in table 3.

TABLE 3

	Measuring unity	1965	1975	1980	1989
Cement production: from which :	10^3 tons	5583	12019	15611	13122
- dry process	%	10.9	58.6	71.4	86.6
- wet process	%	89.1	41.4	28.6	13.4

At the same time, efforts have been made in view of cutting down energy specific consumptions (i.e. cutting down particularly the fuel meant fot clinker manufacturing) for both technologies. The unitery capacity of clinker furnaces has increased according to the dry procedure from 800 t/day to 3000 t/day, as well as the clinker heat recovery degree. Therefore, fuel specific consumptions meant fo getting the clinker have favourably developed as shown in table 4.

TABLE 4

	Measuring unity	1965	1975	1980	1989
Wet procedure	kJ/kg	7170	6780	6550	6295
Dry procedure	kJ/kg	6220	4100	3980	3710
Average specific consumption	kJ/kg	7020	5210	4825	4065

The iron and steel industry has witnessed a decrease of the Siemens Martin procedure share for steel production, simultaneously with the increase of the converter steel share. Table 5 shows the process :

TABLE 5

	Measuring unity	1965	1975	1980	1987
Steel production from which:	10^3 tons	3426	9549	13175	13885
-Siemens Martin	%	91.8	49.9	36.7	30.0
-converter	%	-	37.4	43.6	46.1
electrical	%	8.2	12.7	19.7	23.9

150

Such examples can be mentioned in other branches as well.

An important contribution for meeting this favourable development proper to the previous decade (available, to a certain extent, at present as well) was made by several technology imports carried out in the respective period.

After 1980 the economic situation further on changed, two factors making their important contribution to this.

On the one hand, the second oil shock changed the conditions on the energy international market, pointing out the already availab difficulties in the country.

On the other hand, the overall and rapid payment of external debts became a highly important political target for the country's leadership of that period.

New issues have occured which could not be always successfull solved up.

The hopes related to the energy internal production enhancening have failed and the plan figures have not been met. Thus, an oil production of 12.500 million tons was planned for 1985, but only 10.5 million tons were extracted. A lignite production of 75 milion tons was planned, but only 37.1 milion tons were achieved. The unave lability of free currency have weakened the connections with the world market bringing about negative effects both with respect to th supply of energy resources and with respect to industrial technologies retrofitting (and not only the industrial ones). At the same time the industrialization developed within the conditions of planne economy kept its strategic objective character from the economical and political viewpoint.

Under these circumstances, during 1980 - 1987 the primary ene gy consumption at the national level increased with 14.7% (respectively from 2.79 . 10^{18} J to 3.13 . 10^{18} j). However, important changes occured with respect to the structure of this consumption according to the national economy branches. These changes are shown in table 6 - in percentages

TABLE 6

	1980	1987
OVERALL CONSUMPTION	100	100
from which		
- industry	68.9	74.2
- agriculture	4.6	3.8

	198o	1987
- household consumption	1o.5	9.o
- transportation	5.1	3.3
- public administration	1.2	o.2
- buildings	2.6	2.1

As a matter of fact, during the analysed period, energy consumption share in industry increased both with respect to the overal consumption and to the absolute values. Energy consumption in the other branches (consumption meant for population being included) decreased both with respect to its share and to its absolute value (although the inhabitants number increased with 3.3% during that period). Such a policy has led to important economical and social strains.

Considering the development of electrical energy consumption, the situation is not qualitatively changed . During 198o-1987 electrical energy consumption at the national level increased from 67.4 TWh to 75.2 TWh (therefore with 18.6%). The consumers within all economic branches could be hardly supplied with electrical energy during that period. However, the general phenomenon known as "energy electrification" occured in our country as well. Electrical energy consumption witnessed a higher increase as compared to the primary energy consumption. The consumption structure on various branches developed as shown below, in table 7.

TABLE 7

	198o	1987
OVERALL CONSUMPTION	1oo	1oo
from which :		
-industry (including the own consumption of electrical power station)	78.3	79.5
- agriculture	4.4	5.2
- household consumption	7.5	6.4
- transportation	3.o	3.4
- public administration	1.8	1.8
- buildings	2.4	2.o

There follows that the industrial consumption share whose lev is already high, kept on increasing, reaching at almost [illegible]% of the overall consumption.

152

A certain share increase in the overall consumption has been also recorded in agriculture and transportations - due to the need of increasing the technical level of these branches. The category which witnessed the highest consumption regress (both as share and as absolute values) is the population. The previous conclusion on the effects of energy supply for industry to the prejudice of population (i.e. important social stresses were gathered up) remains valid.

Several data will be further on shown concerning electrical energy consumption in industry. The synthetic data are shown in table 8 :

TABLE 8

	1980	1987
Total Industry	100	100
1. electrical and thermal energy generation	13.8	14.0
2. fuel	6.9	9.5
3. ferrous metalurgy	12.1	14.1
4. nonferrous metalurgy	12.0	10.4
5. machine building	12.7	13.5
6. chemistry	22.1	20.1
7. building materials	5.5	4.6
8. light industry	3.8	3.3
9. food industry	2.8	2.9

The increase of inner consumption share of thermal power stations and of the fuel branch can be easily explained by technical reasons. Low heat power lignite burning in thermal power stations brings about higher consumptions. Similarly, the worsening of fuel operating conditions leads to an important increase of the energy consumptions implied in this operation.

The large energy consuming branches in the Romanian industry were and kept being the metalurgic industry (ferrous and nonferrous) and the chemical industry, both of them consuming almost half of electrical energy amount supposed for the whole industry (46.3% in 1980 and 44.6% in 1987). Unfortunately, these values do not meet the shares of these branches with respect to the industrial production value achieved at a national level, shares which, in 1980 had the following values :

- ferrous metalurgy : 7.4%
- nonferrous metalurgy : 3.2%
- chemistry : 8.7%

The light, food and consumption assets production industries have, each on turn or all together, a relatively reduced share in the electrical energy consumption, a share which has sharply decreas in the light industry. This decrease has been entailed both by the production decrease - at a certain basic products - within the analys period.(flax, hemp and mixed fibres at 41.6 thousands tons, woolen fibres from 77.6 thousands tons to 75.9 thousands tons, cotton fibres from 187 tgousands tons to 172 thousands tons, knit goods from 336 milion pieces to 275 milion pieces etc).

Mention should be made that from the valoric considerations , these branches highly make their contribution at the overall industrial production (light industry with 14%, food industry with 12.8% in 1980).

It may be presently estimated that primary energy and electrical energy consumption are quite disproportional (i.e. an exagerated consumption share in industry and particularly in the metalurgical and chemical industries) and have a small share of other branches (household consumption, agriculture, transportations). These structures are due to the the previously promoted political factors of the respective period. As far as a market economy is promoted in Romania, the energy consumption structure is likely to be correspondingly changed.

9

The demand for gasoline

Further evidence

Leonidas P. Drollas

Sufficient time must be allowed to elapse to assess fully the response of gasoline demand to price changes. Hitherto, empirical work on the subject has generally not examined the period beyond 1975; moreover, the extant time-series studies concentrate almost exclusively on the USA. This study extends both the observation period and the country coverage. A vehicle stock-adjustment model is estimated via its reduced form without explicit consideration of the vehicle stock itself. However, the estimation procedure incorporates the structure by way of constraints on the parameters. Cross-section analysis offers additional evidence concerning the truly long-run price elasticity. The results suggest that there is no need to resort to elaborate models to explain adequately gasoline demand. Gasoline demand exhibits a long-run price elasticity near unity with time lags exceeding six years, while there is tentative evidence that the duration of these lags is not fixed.

Keywords: Gasoline demand; Prices; Lags

Though gasoline has received in the empirical literature the amount of attention that befits its status in the family of oil products, most extant studies and models are based on data up to 1975 and are preoccupied with the USA, especially in a time-series context. This study seeks to redress the balance by examining the period to 1980 and encompassing certain European countries, in addition to the USA.

The author is Manager Economic Studies, Management Sciences Division, Corporate Planning Department, BP International Ltd, Britannic House, Moor Lane, London EC2Y 9BU, UK.

The views expressed in this paper do not necessarily reflect those of the British Petroleum Company; I remain entirely responsible for any errors of commission or omission. I would like to thank all my colleagues in BP for their support and in particular John Mitchell, without whom this study would not have been possible, Alan Solomon, Anne Drinkwater, Pat Williams, and Claire Britchford. Finally, I would like to acknowledge the useful contribution made by an anonymous referee's comments in clarifying certain key issues.

Final manuscript received 23 May 1983.

The need to extend the estimation period to incorporate the years following the 1973/74 oil crisis is particularly strong, since one would not expect to see the full response to the very large price increases within a year or so of the crisis. Moreover, the gasoline markets were rocked by even more severe price increases in 1978/79 due to the Iranian Revolution, and the world is still adjusting to the price jumps set in motion then.

Lest it be thought, however, that this study represents merely an update of existing models, it should be emphasized at the outset that a new approach is used to examine gasoline consumption over time, an approach that is economical in its data requirements and parsimonious regarding estimated parameters, yet succeeds in achieving a high degree of explanatory power. The study also presents evidence regarding the truly long-run price elasticity of demand for gasoline, and examines – albeit cursorily – the possibility that the speed of adjustment in the dynamic time-series models may not be invariant over time.

The main messages that can be gleaned from the empirical analysis can be put succinctly as follows:

0140-9883/84/010071-12 $03.00 © 1984 Butterworth & Co (Publishers) Ltd

153

- most countries in the sample display similarities rather than dissimilarities;
- the long-run price elasticities of demand obtained from the time-series models suggest that although gasoline demand is price inelastic, it is not far from possessing unitary elasticity;
- there is some evidence from a cross-section model that the truly long-run price elasticity is well above unity;
- there appears to be considerable inertia in gasoline consumption due essentially to the slowly changing vehicle stock and habit persistence;
- there is tentative evidence that delays in the response of consumption vary a great deal in length over the years.

In terms of policy implications, the empirical results as they stand suggest that governments in gasoline consuming countries that tend to use taxes on gasoline as a source of revenue rather than, say, an instrument of energy conservation policy, will find the going increasingly tough in the long run – particularly if the price of crude oil keeps on rising inexorably. As far as the oil producing countries are concerned, the results would tend to imply that blind pursuit of oil price increases on the basis of inelastic demand for transport fuels cannot be relied upon to keep producing results in the longer term. Finally, these price elasticities suggest that the limit to the amount of refinery upgrading capacity needed may well be reached sooner rather than later.

Of models and elasticities

The various contributions in the literature are characterized ostensibly by their diversity: some models are based on simple dynamic relationships between gasoline consumption, the price of gasoline in real terms, and real income over time; others examine the variation of gasoline consumption per capita as a function of the price of gasoline, the stock of vehicles per capita, traffic density, real income per capita, etc, across countries in a particular year; still others incorporate elaborate vehicle-stock determining relationships in addition to examining the utilization rate of this stock.

I use the word 'ostensibly', because most of these models share a common logical foundation based on the self-evident idea that gasoline is consumed by way of an existing stock of vehicles; the differences between the models can then be ascribed essentially to the extent to which the models take into account explicitly the stock of vehicles and the factors affecting both the stock itself over time and its utilization rate.

Conceptually, the relationship between gasoline consumption and the vehicle stock is enshrined in the following identity:

$$G \equiv \sum_{i=1}^{K} \frac{MIL_i}{MPG_i} \qquad (1)$$

where

G = total consumption of gasoline per time unit
MIL_i = miles driven in the ith vehicle per time unit
MPG_i = miles per gallon achieved by ith vehicle
K = number of vehicles

Notice how the identity above – like all tautologies – is devoid of any real interest as it stands. However, if we assume à la Sweeney[1] that the vehicle population is segmented into vintages, each vintage representing a model year with certain characteristics shared by all vehicles of that year such as mileage driven and efficiency, we can derive a meaningful aggregate relationship as follows.

Writing,

$$G = \frac{MI_1 \cdot K_1}{mpg_1} + \frac{MI_2 \cdot K_2}{mpg_2} + \ldots + \frac{MI_j \cdot K_j}{mpg_j} + \ldots \qquad (2)$$

where

MI_j = miles driven per vehicle per time unit in jth vintage
mpg_j = efficiency of jth vintage (in time unit considered)
K_j = number of vehicles in jth vintage

Multiplying (2) by $(MI \cdot K)/(MI \cdot K)$, where MI represents the average mileage driven per vehicle as far as the whole fleet is concerned and K is the total number of vehicles in existence, yields the following:

$$G = \left\{ \sum_{j=1}^{J} \frac{1}{mpg_j} \frac{(MI_j)}{(MI)} \frac{(K_j)}{(K)} \right\} MI \cdot K \qquad (3)$$

ie

$$G = \frac{MI}{MG} \cdot K \qquad (4)$$

where

$$MG = 1 / \left\{ \sum_{j=1}^{J} \frac{1}{mpg_j} \frac{(MI_j)}{(MI)} \frac{(K_j)}{(K)} \right\} \qquad (5)$$

is a weighted harmonic mean of the efficiencies characterizing each vintage – in other words, a variable representing the average fuel efficiency of the whole vehicle population.

Furthermore, if we assume that the average distance driven within the time unit (for argument's sake, a year) is a function of the real price of gasoline among other influences – as indeed one can hypothesize about both the car stock itself and its average efficiency – Equation (4) is then transformed into the following behavioural equation:

$$G = \frac{MI(Pg^*)}{MG(Pg^*)} \cdot K(Pg^*) \qquad (6)$$

where

Pg^* = real price of gasoline
(. .) = functions

It is easy to see that Equation (6) above implies the following relationship between the various price elasticities of demand:

$$Eg \cdot p = Emi \cdot p - Emg \cdot p + Ek \cdot p \qquad (7)$$

where

$Eg \cdot p$ = price elasticity of demand for gasoline
$Emi \cdot p$ = elasticity of response of distance to gasoline price
$Emg \cdot p$ = elasticity of response of efficiency to gasoline price
$Ek \cdot p$ = elasticity of vehicle stock to gasoline price

Thus, when the price of gasoline increases in real terms, a whole sequence of behavioural responses is set in motion, whereby people start to drive less, to drive these fewer miles more carefully, to exchange their less efficient vehicles for more efficient ones, and finally to own fewer vehicles than they would have done otherwise. The total effect of the real price increase on gasoline consumption is of course given by $Eg \cdot p$ in Equation (7) above.

Bearing in mind the microfoundations of gasoline consumption already presented, it is apposite at this stage to examine a few empirical results from studies of gasoline demand to be found in the literature. The list of results displayed in Table 1 is by no means exhaustive; however, it is hoped that most of the more important papers have been covered.

As mentioned in the introduction, there is an overwhelming bias in the literature – as can readily be seen from Table 1 – towards the USA. Hence, there are all kinds of models that have been estimated for the USA, ranging from the traditional time-series analysis of a simple gasoline demand equation incorporating a lagged dependent variable,[2] to single-equation pooled cross-section/time-series models,[4,5] to multi-equation time-series models.[3,11,13] The consensus view regarding the USA seems to be that the long-run price elasticity of demand lies around −0.80, while the long-run income elasticity is slightly below unity. As far as other countries are concerned, the limited evidence on offer suggests that they do not differ substantially from the USA. It is hoped that the following sections will prove to be of use in corroborating or refuting this consensus view.

Table 1. Price and income elasticities of demand for gasoline.

Study	Type, coverage	Price elasticity		Income elasticity	
		Short run	Long run	Short run	Long run
1973, Ref 2	Time series, USA, 1950–73, lagged dependent variable	−0.07	−0.23	0.28	0.94
Rand Corporation, 1974, Ref 3	Time series, USA, 1950–73, separate equations for the components	−0.26 *Emi.p* = −0.36 *Emg.p* = 0.17 *Ek.p* = −0.25	−0.78	0.18	0.88 ↑ Ownership
Houthakker *et al*, 1974, Ref 4	Dynamic pooled time series, USA, states, quarterly 1963–72	−0.075	−0.24	0.303	0.98
Charles River Associates, 1975, Ref 5	7-region pooled time series, USA, 1950–73	−0.28	−1.37	0.012	0.06
Houthakker and Kennedy, 1975, Ref 6	Logarithmic flow-adjustment, 12-OECD countries, 1962–72, cross-section/time-series	−0.47	−0.80	0.74	1.33
Ramsey *et al*, 1975, Ref 7	Time series, no dynamics, USA, private demand, annual 1947–70	−0.77		1.34	
FEA, 1976, Ref 8	Time series, vehicle-miles (vm), aggregate, USA	−0.48		0.98	
Sweeney, 1978, Ref 9	Time series, vehicle-miles (vm), USA, 1950–73	*Evm.p* = −0.22	*Emg.p* = 0.72 *Evm.p* = −0.06		0.82
Pindyck, 1979, Ref 10	Pooled 11 countries time series, 1955–73	*Ek.p* = −0.26 *Emg.p* = 0.11	*Ek.p* = −0.64 *Emg.p* = 1.43	*Emi.y* = 0.06 *Ek.y* = 0.12	*Emi.y* = 0.66 *Ek.y* = 0.30
Archibald and Gillingham, 1981, Ref 11	*G, MI, MG* equations, no *K*, USA, monthly data, 1972–74	1 car −0.77 2 car −0.22		1 car 0.29 2 car 0.56	
Wheaton, 1981, Ref 12	Cross national, 25 countries, 1972, no dynamics	*Eg.p* = −0.78 *Emi.p* = −0.52 *Emg.p* = 0.32 *Ek.p* = 0.16 (!)		*Eg.y* = 1.20 *Emi.y* = 0.52 *Emg.y* = −0.19 *Ek.y* = 1.26	
R[illegible]n, 1982, Ref 13	Time series *G, MI, MG, K* equations, 1960–78, dynamic, USA	−0.49	−0.98		

Is an explicit treatment of vehicles necessary?

Gasoline, along with most other fuels that are consumed to generate power, obviously needs a stock of vehicles or machinery (eg lawnmowers) to exist for consumption to be possible. This trite remark has to be made again at this juncture in order to draw a comparison between the treatment of, say, heating gas oil and gasoline. In the case of heating gas oil, no one seriously proposes counting the number of oil-fired boilers in existence in order to arrive at a stock figure, which in combination with a utilization rate would yield heating gas oil consumption. One has to try to explain gas oil consumption via some other route that obviates the need to know the exact number of boilers in existence. Why, then, do most gasoline studies lay so much emphasis on the vehicle stock and its technical characteristics?

The main reason seems to be a practical one. Vehicle stock data are available in most developed countries, unlike boiler stocks. Fiscal authorities consider the taxation of vehicles a matter of utmost importance and are prepared to go to extraordinary lengths to maintain registers of vehicles. Moreover, it all sounds so logical – given the number of vehicles, miles driven per vehicle, and the technical efficiency of each vehicle, gasoline consumption drops out by way of an identity! Or does it?

As we have seen above, the only *true* identity is the summation over K vehicles of miles driven – at a certain mpg – by the ith vehicle (Equation (1)). On the other hand, one can arrive at an equation with operational significance (see the derivation of Equation (4) above) by assuming that all vehicles fall into distinct vintages. However, one assumption made en route in the derivation, and another required to allow one to obtain in practice a weighted harmonic mean of efficiencies, conspire to cast a shadow over those studies that rely heavily on published vehicle fleet efficiencies and average miles driven. The first assumption – that all vehicles within a common vintage are driven the same number of miles per time unit and possess the same efficiency – is required to be able to segment the sample into vintages, while the second – that all vintages share a common number of miles driven (ie $MI_j = MI$ all j, in (5) above) – is required to obtain in practice a measure of vehicle fleet efficiency by weighting the estimated efficiencies of each vintage only by the share of each vintage in the total vehicle stock (ie K_j/K in (5)) and not by relative vehicle-miles. In fact, I am given to understand that the 'miles-travelled' statistics in the USA are obtained by calculating the average fleet efficiency in the manner suggested and then multiplying this efficiency figure by total gasoline consumption. A further practical complication in the case of the European countries considered is that efficiency statistics by vintage, and indeed the number of vehicles in each vintage, are not readily available.

Without wishing to denigrate the efforts of those authors who have made use of published miles-per-annum and mpg data, it is the contention of this paper that one need not resort to particularly elaborate equation systems based on such data to explain a high proportion of the variation in gasoline consumption over time. Furthermore, one need not use vehicle stock data either.

The key to our understanding of the forces governing the consumption of gasoline over time lies in the behavioural functions associated with each of the elements mentioned above. In line with other studies, it is assumed that economic variables influence both the desired stock of vehicles and the utilization rate of this stock. However, unlike other studies, it is felt that one need not be specific about the vehicle stock and vehicle miles – algebraic substitution and constrained estimation usually suffice.

Bearing in mind the points made above, the relationship between the amount of gasoline consumed within say a year, the vehicle stock, and its utilization rate, can be written as:

$$G_t = U_t \cdot K_t$$

ie

$$\ln G_t = \ln U_t + \ln K_t \qquad (8)$$

where U = utilization rate.

The utilization rate U incorporates both notional miles driven per annum and average efficiency, and is specified as a constant elasticity function of the real price of gasoline and real income, ie

$$\ln U_t = a_0 + a_1 \ln (Pg/P)_t + a_2 \ln Y_t \qquad (9)$$

where

Pg = nominal price of gasoline
P = prices of all other goods
(NB $Pg_t^* = (Pg/P)_t$)
Y = real income

Note that the utilization rate is postulated to be a function of the real price of gasoline only, because it is assumed that the prices of rival forms of transport influence the decision to invest in gasoline-consuming vehicles rather than their utilization rate once they have been purchased (this assumption has been borne out empirically). Furthermore, note that the actual utilization rate (though unobservable) is postulated to equal the desired rate, ie Equation (9) represents an equilibrium relationship, which is not unreasonable given that we are dealing with an annual model.

The actual vehicle stock is assumed to adjust towards its desired level with a lag due to what has been termed 'habit persistence', but which in fact encompasses information, decision, and investment delays. These delays are typically considered to be the result of two antithetical forces: one, based on the cost of being out of equilibrium, forcing the pace of change, with the other, based on the cost involved in actual change, retarding change. Another way of looking at it is to assume that the actual vehicle stock at any moment is not determined solely by the current levels of certain relevant factors (eg real income, the price of vehicles, etc) but also by past levels of these factors, with the effect on the present of more remote periods being discounted more heavily than that of more recent periods. Viewed in this manner, the size of the existing vehicle stock in an extreme case

could owe more to developments some time ago than current conditions.

At any rate, whichever way one looks at it results in similar dynamic adjustment mechanisms in discrete time, if one does not take explicitly into consideration the error terms. For example, the widely used partial adjustment hypothesis or 'habit persistence' model referred to above yields a final equation virtually identical to an equation obtained by way of the second route that assumes the discounting of the past follows a pattern of geometric decay – the Koyck or geometric lag scheme. On the other hand, explicit consideration of error terms both introduces complications and affords us an admittedly convoluted way of distinguishing between the two schemes.*

Without losing sight altogether of certain underlying complexities connected with the error terms, our general ignorance regarding the true structure of the errors means in practice that we may proceed cautiously along simpler trails. Accordingly, comparatively little is lost and much gained by accepting the principle of delayed adjustment (or the intuitively equivalent principle of geometrically declining lag effects) and positing the following adjustment mechanism:

$$\ln K_t - \ln K_{t-1} = g(\ln K_t^* - \ln K_{t-1}) \qquad (10)$$

where

K^* = desired vehicle stock
g = speed of adjustment $(0 < g < 1)$

The desired vehicle stock in turn is postulated to depend on the real price of vehicles, real income, and the relative price of gasoline with respect to the price of alternative forms of transport in real terms, ie

$$\ln K_t^* = b_0 + b_1 \ln (Pg^*/Pr)_t + b_2 \ln Y_t + b_3 \ln Pc_t \qquad (11)$$

where

Pr = real price of transport services
Pc = real price of vehicles

By straightforward substitution and subsequent algebraic manipulation, it is possible to eliminate the unobservable utilization rate and the stock of vehicles. One is then left with a dynamic equation in terms of the consumption of gasoline and the predetermined variables, ie

$$\begin{aligned}\ln G_t = {} & (a_0 + b_0)g + (a_1 + gb_1) \ln Pg_t^* - gb_1 \ln Pr_t \\ & + (a_2 + gb_2) \ln Y_t + gb_3 \ln Pc_t \\ & - a_1(1-g) \ln Pg_{t-1}^* - a_2(1-g) \ln Y_{t-1} \\ & + (1-g) \ln G_{t-1} \qquad (12)\end{aligned}$$

Estimation of the final-form equation above by way of any single-equation based estimation technique is acceptable if the main intention is to predict rather than obtain parameter estimates. However, if one's primary objective is to unravel the tangled web of relationships that result in Equation (12) without considering explicity the vehicle stock, miles driven per annum, etc, one needs to resort to a method of estimation that allows for parameter restriction during estimation.

Empirical results

The estimation technique used in the case of Equation (12) was Full Information Maximum Likelihood (FIML) with parameter restrictions within equations, while the actual programme used was RESIMUL, one out of a suite of programmes developed by C. R. Wymer[15] to deal with parameter-constrained estimation, among other things. In this instance it might seem we are using a sledgehammer to crack a feeble nut. However, it is the very use of parameter-constrained FIML that allows us to obtain consistent parameter estimates of the implied structural model from the final form, because as the programme iterates on the parameter set to maximize the likelihood function, the constraints implied by the structure and enshrined in the equation to be estimated in the form of functions of parameters (eg $a_2 + gb_2$) are brought into play to limit the extent to which particular parameters can vary during the maximization procedure. There is another factor in favour of the use of FIML estimation when dealing with Koyck lags. As Morrison[16] has shown, the methods that have given the best estimates of the parameters of the familiar geometric lag have involved numerical approximations to the maximum likelihood solution.

Before the main results of the estimation are presented, it is apposite to discuss briefly the vexed question of lag structures. The ubiquitous Koyck[17] lag was used in the model presented above essentially because of its popularity and recognizability. However there is no theoretical reason why the lag structure should follow a pattern of geometric decline. Indeed, early on in the history of lag schemes, Solow,[18] Almon,[19] and Jorgenson[20] all generalized the lag structure in such a way as to include the geometric lag as a special case of the general scheme.

Perhaps the best way to visualize the more general lag pattern put forward by these authors in juxtaposition to the Koyck lag is to consider Figure 1.

Imagine that the dependent variable in question – represented by "y" – is in equilibrium, which means that

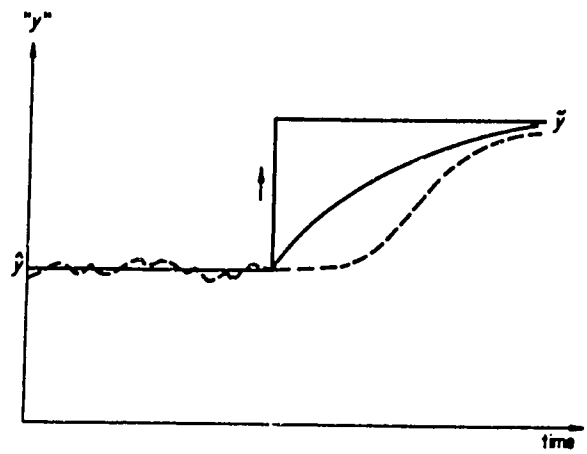


Figure 1. Delayed responses to a step change.

*For details see pp 33–34 in Griliches, Ref 14.

it follows its desired level (given by "y") apart from a random variation around it. Then imagine that a change occurs in the behavioural function that determines the desired level and that this level increases. The geometric lag response of "y" would follow the solid line, while the alternative lag scheme would cause "y" to follow the dashed line. In the latter case, there is little response initially to the new desired level, then an accelerated response, and finally a slowing down as "y" approaches the new equilibrium. Many researchers have found the inverted-V lag† a more plausible lag structure since Solow introduced it in 1960. It is felt that people tend to delay their response until they are sure that the circumstances that led to the new desired level – such as a real price increase, in the case of a demand function – are likely to persist. Change is not costless, and people would be reluctant to invest, for example, in new more fuel-efficient equipment if they believed that an energy price increase in real terms is merely a temporary aberration due to particular conditions prevailing at the time.

At any rate, the Solow generalization can be written as follows in terms of the variables dealt with in this paper:

$$\ln K_t = \sum_{i=0}^{\infty} c_i \ln K^*_{t-i} \tag{13}$$

where

$$c_i = \binom{r+i-1}{i} (1-g)^r g^i \tag{14}$$

In other words, Solow postulated that the actual variable is a distributed lag function of its desired level in the current and all previous periods, the distributed lag scheme being represented by coefficients c_i that follow a Pascal distribution. It can be shown quite easily that the Solow scheme boils down to the geometric lag if r above equals unity. If, on the other hand, $r=2$, the Solow pattern becomes

$$\ln K_t = 2g \ln K_{t-1} - g^2 \ln K_{t-2} + (1-g)^2 \ln K^*_t \tag{15}$$

Incorporation of Equation (15) above into the system of equations we have been dealing with instead of Equation (10) yields the following final-form equation:

$$\begin{aligned}\ln G_t = {} & (a_0 + b_0)(1-g)^2 + (a_1 + b_1(1-g)^2) \ln Pg^*_t \\ & -(1-g)^2 b_1 \ln Pr_t + (a_2 + b_2(1-g)^2) \ln Y_t \\ & +(1-g)^2 b_3 \ln Pc_t - 2a_1 g \ln Pg^*_{t-1} \\ & -2a_2 g \ln Y_{t-1} + a_1 g^2 \ln Pg^*_{t-2} + a_2 g^2 \ln Y_{t-2} \\ & +2g \ln G_{t-1} - g^2 \ln G_{t-2}\end{aligned} \tag{16}$$

Equation (16) is merely a more elaborate version of the final form in the case of the geometric lag – Equation (12). The econometric arguments in favour of FIML estimation with parameter constraints that were vented regarding geometric lags apply *a fortiori* in the case of inverted-V lags.

The most sensible course of action to take empirically is to remain sceptical as to whether the true lag scheme is a geometric or an inverted-V scheme, and estimate both formulations. This has been done for the five developed countries that had the requisite data sets readily available. The estimation results are presented in Table 2.

The first impression one gets looking at Table 2 is of similarity rather than diversity between the countries. One also soon observes that the differences between the two lag schemes are not striking in terms of the parameters they both yield. Detailed commentary on the results can be put succinctly as follows:

- The speed of adjustment‡ of gasoline demand to changed circumstances is slow, full adjustment taking more than 7 years. Moreover, the results suggest that the lag in consumption can be identified with the slowly changing vehicle stock. There is broad agreement on the speed of adjustment among countries.
- There is an identifiable short-run effect of the real price of gasoline on the demand for gasoline, which works principally through the utilization rate. Again, there are strong similarities between countries regarding the magnitude of this short-run price elasticity.
- As far as the effect of a change in the level of economic activity on the utilization rate is concerned (ie parameter a_2), the empirical work drew a blank apart from the USA. William Wheaton[12] provides an unsolicited explanation for this, since he found that increases in income do lead to more miles driven, but the increases in income also lead to more vehicles (per capita), and more vehicles per capita tend to lead to fewer miles driven per vehicle. Our formulation does not allow for these opposing effects explicitly, and logic dictates that the results would be particularly inconclusive in countries with a rapidly increasing vehicle stock per capita (most European countries would fit this bill in the post-WWII period in contrast to the USA).
- The long-run income effect on gasoline demand operates through the effect of income or activity on the desired vehicle stock (parameter b_2). The evidence from the estimation is overwhelmingly in favour of unitary elasticity as far as the European countries are concerned. In the USA, it appears that vehicles are considered necessities (b_2 well below unity – in fact, not significantly different from zero). This latter point seems to accord well with the role of the private automobile in the American way of life.
- There is some evidence of an effect of the price of vehicles on gasoline demand via its effect on the vehicle stock (UK, France, USA). However, this effect is relatively small and takes a long time to influence demand.

†The lag scheme owes its description as such to the plot of the derivative, which resembles an inverted-V in that it first rises, reaches a peak, and then falls away

‡The speed of adjustment parameter g can be reinterpreted in terms of the time taken for 90% of adjustment of the actual to the desired level to occur. Thus, $(2.3/g)$ and $(4/g)$ yield the time in years for the Koyck and inverted-V models respectively.

160

Table 2. Final form of gasoline demand model based on vehicle stock adjustment.

Country/model	g	a_1	a_2	b_1	b_2	b_3	Price elasticity Short run	Price elasticity Long run	Years for 90% adjustment	Root mean square % error	x^2 (DF)	$\bar{R}^2$
UK: geometric lag	0.23 (3.8)	−0.20 (3.2)	−0.08[a] (5.6)	−0.35 (1.6)	1.29 (4.5)	−0.65 (3.4)	−0.28 (5.9)	−0.55 (2.8)	10	1.75	2.6 (2)	0.9989
UK: inverted-V lag	0.62 (8.2)	−0.17 (3.4)	−0.08[a] (7.2)	−0.45 (1.7)	0.98 (2.7)	−0.56) (2.3)	−0.24 (4.9)	−0.62 (2.2)	7	1.57	17.4 (6)	0.9991
W. Germany: geometric lag	0.35 (3.0)	−0.19 (1.5)		−0.62 (3.5)	1.15 (8.5)	−0.56 (0.9)	−0.41 (5.8)	−0.82 (5.5)	7	1.97	0.29 (1)	0.9995
W. Germany: inverted-V lag	0.46 (5.3)	−0.25 (2.0)		−0.95 (2.8)	1.07 (6.3)	−0.88 (1.4)	−0.53 (7.6)	−1.20 (4.4)	9	2.08	5.4 (3)	0.9993
France: geometric lag	0.24 (3.4)	−0.39 (8.5)		−0.19 (1.3)	1.08 (15.1)	−0.44 (3.3)	−0.44 (12.2)	−0.58 (4.8)	10	1.08	0.001 (1)	0.9996
USA: geometric lag	0.23 (3.4)	−0.24 (3.7)	0.55 (2.8)	−0.48[b] (2.0)	0.34 (1.5)	−0.64 (2.8)	−0.35 (9.4)	−0.73 (3.6)	10	1.10	1.1 (1)	0.9987
USA: inverted-V lag	0.61 (8.1)	−0.24 (5.6)	0.72 (5.2)	−0.46[b] (2.1)	0.21 (1.3)	−0.51 (2.1)	−0.32 (8.5)	−0.70 (3.6)	7	0.97	4.81 (3)	0.9989
Austria: geometric lag	0.39 (4.0)	−0.34 (2.9)	0.35 (0.7)	−0.48 (4.8)	1.02 (2.2)	−0.34 (1.1)	−0.52 (6.9)	−0.82 (9.5)	6	2.07	1.8 (1)	0.9989
Austria: inverted-V lag	0.45 (4.4)	−0.43 (3.8)		−0.47 (4.2)	1.39 (11.9)	−0.42 (1.1)	−0.57 (7.8)	−0.89 (7.8)	9	2.06	19.3 (3)	0.9987

Notes:
Estimation covers period 1950–1980. Method of estimation is FIML with non-linear parameter restrictions. x^2 test with indicated degrees of freedom (DF) examines the appropriateness of the over-identifying parameter restrictions. t values in parentheses.
[a] Dummy variable used to capture effect of Suez crisis.
[b] Real price of gasoline used in vehicle stock equation.

- The one quantity of prime importance to oil producers, oil companies, and governments in oil-consuming countries is the long-run price elasticity of demand for gasoline. Table 2 shows that the estimates are certainly above −0.5, and in the case of West Germany, Austria and the USA, the estimates are not statistically significantly different from unity. Of the two components that make up the long-run elasticity (a_1 and b_1), the effect of the price of gasoline on the vehicle stock is dominant in all cases.
- On the whole, the two lag formulations yield parameters that are statistically indistinguishable, apart that is from West Germany's b_1, Austria's a_1, and the USA's a_2. Naturally, the speeds of adjustment cannot be tested for equality, because they have differing interpretations (eg if both lag formulations imply a 10 year lag for 90% adjsutment, then the geometric-lag speed of adjustment parameter will have the value 0.23 whereas the inverted-V will be 0.4).
- The explanatory power of these single-equation final form models is quite high, as can be ascertained from their low RMSEs (Root Mean Square Errors). Furthermore, in most cases the x^2 test is passed, implying that the parameter restrictions imposed on the models are valid, ie the underlying structure is as specified.

Further results: five more countries and a variable speed model

Before examining the likely magnitude of the price elasticity of demand for gasoline in the really long run, it is apposite to present the results of two further bits of analysis pertinent to the time-series models examined so far. Table 3 contains the results from estimating a conventional partial adjustment model§ of gasoline demand, based on a geometric lag mechanism from Equation (10), for a further five European countries over the period 1955–80. The reason why simple lag models have been estimated in this case is because it was not possible to obtain satisfactory data for series such as the price of vehicles and the price of public transport in these countries.

The salient features of this analysis can be stated simply as follows. First, though the estimated long-run price elasticities appear in most cases – except Sweden – to be well above unity, they are not statistically significantly different from unity. The previous point applies equally to the income elasticity of demand – except for Belgium and Sweden. The lags implied by the speeds of adjustment are broadly similar across this small sample of countries. The RMSEs are of the same magnitude and uniformly higher than the corresponding errors in the more complete models presented before. Since the countries for which full data sets exist yielded better results in the case of the implied vehicle stock model than the elementary partial adjustment model, there is every reason to believe that this would have been

§This model is written

$$\ln G_t - \ln G_{t-1} = k(\ln G_t^* - \ln G_{t-1})$$

where the desired level of gasoline demand G^* is given by

$$\ln G_t^* = c_0 + c_1 \ln Pg_t^* + c_2 \ln Y_t$$

Table 3. Simple lag models of gasoline.

Country/model	Price Short run	Price Long run	Income Short run	Income Long run	Years 90%	x^2 (DF)	Root mean square (%)
Belgium:							
geometric lag	−0.48	−1.62[a]	0.38	1.27	8	0.0	3.2
	(4.7)	(2.3)	(1.7)	(9.1)		(0)	
inverted-V lag	−0.50	−1.17[a]	0.57	1.34	11	3.7	3.5
	(4.4)	(3.7)	(2.9)	(16.7)		(1)	
Italy:							
geometric lag	−0.41	−1.08[a]	0.31	1.34[a]	10	0.0	4.4
	(4.6)	(5.7)	(2.4)	(7.1)		(0)	
inverted-V lag	−0.38	−1.44[a]	0.39	1.46	8	3.5	4.6
	(3.6)	(6.2)	(3.1)	(11.5)		(1)	
Netherlands:							
inverted-V lag	−0.29	−1.81[a]	0.18	1.11[a]	7	2.1	4.6
	(1.3)	(1.3)	(1.6)	(4.1)		(1)	
Sweden:							
geometric lag	−0.17	−0.52	0.46	1.46	7	0.0	2.3
	(2.7)	(2.0)	(2.6)	(11.7)		(0)	
inverted-V lag	−0.16	−0.37	0.65	1.50	12	2.1	2.3
	(2.5)	(2.1)	(3.6)	(20.3)		(1)	
Denmark:							
geometric lag	−0.38	−1.07[a]	0.31	0.86	6	0.0	4.4
	(2.8)	(3.4)	(1.6)	(3.3)		(0)	
inverted-V lag	−0.31	−1.27[a]	0.14	0.57[a]	8	1.6	3.8
	(2.9)	(3.0)	(1.1)	(1.6)		(1)	

Notes:
Method of estimation is FIML with parameter restrictions within the equation. x^2 test with indicated degrees of freedom (DF) examines the appropriateness of the over-identifying parameter restrictions. t values in parentheses.
[a] Indicates parameters that are not statistically significantly different from unity.

the case had one been able to obtain the relevant series for the second set of countries as well.

The second bit of analysis is potentially of great importance, if it proves to be relevant in the case of other countries also. The USA has been used as a test bed in this section more in the spirit of a 'scouting party' than an 'armoured column'. At issue is whether the speed of adjustment of the vehicle stock (see Equation (10)), which has been assumed to be constant, is in fact variable. As both Feige[21] and Griliches[14] have shown, the partial adjustment scheme exemplified by Equation (10) can be derived from the minimization of a quadratic cost function that combines the cost of being out of equilibrium with the cost of adjusting towards the new equilibrium. The interesting result from our point of view is that the mean time lag implied by the partial adjustment scheme is a function of the two costs, ie

$$\text{Mean time lag} = \frac{1-g}{g} = \frac{B}{A} \tag{17}$$

where

B = cost of adjusting
A = cost of being out of equilibrium

Now, if one (or both) of the costs are not constant, but depend on some other variable – for example, the cost of adjusting may depend on the rate of interest, while the cost of being out of equilibrium may depend on the magnitude of the disequilibrium itself – the speed of adjustment will vary over time.

The main factor leading to a variable speed in the case of the gasoline models based on the partial adjustment scheme over the period examined would in all probability be the real price of gasoline, the only variable that changed dramatically during the sample period. Therefore, it has been assumed that the speed of adjustment in the USA case is a function of the real price of gasoline, thus

$$g_t = m_0 + m_1 \ln Pg_t^* \tag{18}$$

Substitution of Equation (18) in the final-form Equation (12) above♦ yields the following estimating equation:

$$\begin{aligned}\ln G_t = {} & m_0(a_0 + b_0) + (a_1 + m_0 b_1 + (a_0 + b_0)m_1) \ln Pg_t^* \\ & + (a_2 + m_0 b_2) \ln Y_t - a_1(1 - m_0) \ln Pg_{t-1}^* \\ & - a_2(1 - m_0) \ln Y_{t-1} + m_1 b_1 (\ln Pg_t^*)^2 \\ & + m_1 b_2 (\ln Pg_t^* \ln Y_t) - m_1 (\ln Pg_t^* \ln G_{t-1}) \\ & + a_1 m_1 (\ln Pg_t^* \ln Pg_{t-1}^*) + a_2 m_1 (\ln Pg_t^* \ln Y_{t-1}) \\ & + (1 - m_0) \ln G_{t-1}\end{aligned} \tag{19}$$

♦Note that Equation (12) as estimated for the USA does not have a real price of transport in the desired vehicle stock equation, as this was not found to be statistically significant.

It is immediately apparent that Equation (19) is non-linear in the variables, as indeed it might be apparent that with $m_1 = 0$, Equation (19) boils down to the familiar Equation (12). Non-linear estimation would normally present estimation problems in a simultaneous-equation context. However, in this case we have to deal only with a single equation, which means that the right-hand-side variables can be constructed independently and treated as normal regressors. The implicit structure is embodied in the relationship between the parameters, as we encountered in the case of Equation (12), and all appears to be plain sailing. However, perils lurk just beneath the surface in the form of a parameter identification problem. The parameters concerned are m_0 and the combination $a_0 + b_0$ (which cannot be separated into a_0 and b_0 and must therefore always be estimated as a sum). Attention is drawn to the fact that m_0 and $(a_0 + b_0)$ appear both as a weighted sum and a product, ie

$$a_1 + b_1 m_0 + m_1(a_0 + b_0) = K_1$$

$$m_0(a_0 + b_0) = K_2 \qquad (20)$$

where the other parameters are all identifiable. Thus, m_0 and $(a_0 + b_0)$ are the roots of a quadratic equation, and the estimation procedure cannot distinguish between the two. All is not lost, however, if we could only obtain an independent estimate of either m_0 or $(a_0 + b_0)$, for then we can iterate between the two parameters by treating one of them as a constant, estimating the other, then treating that as a constant and estimating the first as a parameter, and so on until the parameters converge to stable values. Fortunately, we have an initial value for $(a_0 + b_0)$ from our prior estimation of Equation (12), and it is this value (12.26) that serves as the starting point.

It took only seven iterations for the parameters m_0 and $(a_0 + b_0)$ to converge to values that changed by only 0.4% and 0.03% respectively. The full results of the final iteration are presented in Table 4.

There is reasonably strong evidence that the speed of adjustment is indeed variable, with an average value over the sample period of 0.225 (90% adjustment in 9 years) based on the sample mean of the real price of gasoline. It is interesting to see how close these parameters are to those estimated in the constant-speed case, which seems to suggest that estimation of geometric lag models with *constant* speeds of adjustment is likely to yield long-run parameters that are similar

Table 4. Variable speed of adjustment, USA.

$m_0 = -1.885$ (1.53)
$m_1 = 0.533$ (40.53)
$a_1 = -0.223$ (3.58)
$a_2 = 0.562$ (2.99)
$b_1 = -0.532$ (3.66)
$b_2 = 0.370$ (1.77)
$b_3 = -0.617$ (3.05)

Note:
Values are in parentheses; RMSE = 1.04%; $\bar{R}^2 = 0.9988$.

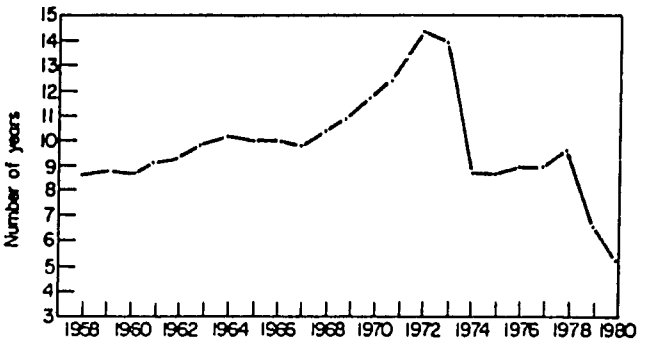


Figure 2. Speeds of adjustment for gasoline in the USA (time taken for 90% adjustment).

to those obtainable from a variable speed model such as the one above, but an adjustment-speed parameter that is an *average* over the sample period. Incidentally, an increased speed of adjustment of the vehicle stock to its desired level due to a higher real gasoline price is compatible with the observed increase in the median age of the US auto fleet since the early 1970s. Stagnating real income and higher real gasoline prices combine to reduce the desired vehicle stock from the level it would otherwise have attained had income and prices followed their 1960s trends, while increased real gasoline prices speed up this process. A lower vehicle stock than would have existed otherwise implies fewer *net* additions to the stock and thus an 'aging' of this stock compare with the earlier period, exactly as the population 'ages' when the birth rate slows down.

The way in which the speed of adjustment varies over time as a function of the real price of gasoline is the prominent feature of this analysis. As can be seen in Figure 2, the time taken for 90% adjustment rose steadily in the 1950s as the price of gasoline fell in real terms, falling subsequently in two large jumps to a 1980 value of 5 years, which is certainly rapid by historical standards. If the speed of adjustment, as indicated by the USA model, is capable of increasing so rapidly, then models based on constant speeds of adjustment might yield biased forecasts in periods when the price of gasoline is increasing by leaps and bounds. One can only say at this stage that variable speeds of adjustment ought to be looked at more closely.

In the really long run . . .

In the long run we shall all be dead, as Keynes so aptly put it. Of course, he was being facetious, to goad his contemporaries into action, fearing that a preoccupation with the future consequences of action (or inaction) might jeopardize one's chances of ever getting there. Is there a need then to consider the demand for gasoline in the very long run, or should we take refuge in Keynes' *bon môt* and let our successors worry about it?

The nature of oil as an exhaustible resource precludes it from being treated like any other good. Arguments about the efficient use of exhaustible resources dictate that demand should be channelled into premium uses, ie where the price elasticity of demand is inelastic in

163

the longer term. Conventional wisdom has it that the demand for the heavier fractions of the barrel is price elastic due to the presence of substitutes (for example, the use of coal, natural gas, and nuclear fuel in power generation) unlike the demand for transport fuels. Therefore, the use of limited oil resources in activities that could use other fuels – fossil or otherwise – might be viewed with disdain, particularly by the oil producers who might feel that their precious asset is being wasted in non-premium uses.

The rights and wrongs of these views notwithstanding, there is a need to examine the factual premises upon which the thrust of such arguments is based – in particular, the extent to which the demand for transport fuels is in fact inelastic in the long run. The evidence gleaned so far from our time-series models tends to show that on the whole the long-run price elasticity of demand for gasoline is not significantly different from unity. The crucial question remains whether this price elasticity could be greater than unity!

To ascertain the magnitude of the long-run price elasticity of demand, we need to identify the long-run demand curve. This in turn can only be done – as far as an individual country is concerned -- by observing a single country over a long enough period, so that different supply conditions, leading to variations in price, can trace out the demand curve. The critics of time-series models contend that an individual country cannot supply a long enough history of gasoline price variation, especially if one includes the decades of the 1950s and 1960s, to enable one to identify the long-run demand curve. What do they suggest instead?

It is felt that there is sufficient variation in the price of gasoline between countries (due mainly to different levels of taxation) to make cross-section analysis the preferred route to take in search of the elusive long-run price elasticity of demand. It is possible in principle to utilize variations across countries to obtain estimates of long-run price and income elasticities, provided one assumes that the underlying economic structure encapsulated in the parameters is invariant with respect to both time and the particular countries forming the group. Of course, these assumptions are not always justifiable, given that elasticities might vary over time and countries will almost certainly differ in terms of the structure of gasoline demand. The first assumption can be tested by estimating the cross-section model at various points in time. The second assumption can be dealt with in two ways: either by using country-specific dummy variables (with a concomitant increase in the number of years considered in order to obtain the requisite degrees of freedom), or by specifying a multi-equation model to account for the special factors representing the intercountry structural differences. In practice, the preferred route has been to include dummy variables and increase the number of observations by estimating 'pooled' time-series and cross-section models. In our case, the 'pooled' approach has been eschewed in favour of the classical cross-section study.

Relevant data covering 37 countries for the year 1977 have been collected in an attempt to estimate a simplified cross-sectional model of gasoline consumption per capita based on this sample. The sample is quite representative, including highly developed countries along with extremely poor countries. Moreover, a particular subset of 24 countries has been used in a two-equation model of gasoline consumption per head and cars per thousand people. The models presented below must be considered as first attempts at cross-sectional analysis; further analysis will be required to improve the accuracy of the estimates. The most important cross-section data are presented in Table 5.

It is obvious from a cursory glance at the data that consumption of gasoline per capita is strongly correlated

Table 5. Cross-section data, 1977.

Country	Consumption per head (gallons)	Cars per thousand[a]	National income per head (SDRs)[b]	Price per gallon (SDRs)[b]
USA	451	525	6484.9	0.59
Canada	309	408	6011.3	0.65
Australia	223	394	5425.5	0.71
Sweden	172	346	6607.6	1.41
New Zealand	149	384	3662.0	1.14
Switzerland	122	305	8877.5	1.72
Iceland	115	316	5520.9	1.64
West Germany	103	333	6769.2	1.82
Denmark	97	271	7072.9	1.77
Great Britain	95	261	3642.9	1.14
France	93	319	5527.4	1.73
Belgium	92	292	6666.5	1.73
Austria	89	263	5055.9	1.64
Norway	84	274	6193.2	1.96
Netherlands	81	282	6171.7	1.73
Ireland	81	179	2428.4	1.45
Finland	79	227	4661.9	1.64
Japan	61	173	4871.5	1.73
Italy	54	289	2827.5	2.14
Cyprus	42	112	1432.4	1.27
Spain	39	162	2238.8	1.27
Brazil	37	58	995.4	1.18
Greece	36	67	2319.8	1.68
Chile	35	28	777.1	1.14
Jordan	30	25	737.3	1.09
Colombia	29	14	527.2	0.23
Portugal	22	101	1295.8	1.75
Turkey	14	13	855.3	1.05
Ethiopia	12	1	87.4	0.68
Thailand	10	8	321.0	0.77
Kenya	6	7	264.6	1.27
Tunisia	4	19	670.8	1.55
Sierra Leone	3	8	169.9	1.18
Sri Lanka	2.4	7	112.1	0.68
Malaysia (W)	2.3	52	893.3	1.18
Niger	1.4	2.2	120.0	1.46
Malawi	0.4	2	131.2	0.64

Sources:
Gasoline and vehicle data from International Road Federation, *World Road Statistics 1974–78*, 1979 edition. National income and population data from IMF, *International Statistics*, various issues.

Notes:
[a] 'Cars per thousand' refer to the total population.
[b] Special Drawing Rights. An SDR is an artificial unit of currency created by the IMF based on a basket of currencies suitably weighted. Each national currency can be expressed in terms of SDRs; the conversions have been performed by the IMF.

with the number of cars per head, which in turn is correlated with national income per capita. However, there are some interesting cases that stand out. Italy exhibits low gasoline consumption per capita in relation to its car population, while Colombia shows an excessive level of consumption per head in relation both to its car population and its income per head. Other cases of interest are Australia and New Zealand, both with roughly comparable car populations per head but differing gasoline consumption levels, and West Germany and Sweden with comparable car populations and income levels but quite different levels of gasoline consumption per capita. Almost all these cases have a common factor, varying gasoline prices, which accounts quite neatly for the discrepancies in gasoline consumption.

The first bit of cross-section analysis that can be performed is to regress gasoline consumption per capita against the price of gasoline and the car population per capita. The result was as follows (t values in parentheses):

$$\ln G_i = 0.07 - \underset{(2.6)}{0.79} \ln Pg_i + \underset{(11.3)}{0.87} \ln C_i \qquad (21)$$

where

$\bar{R}^2 = 0.89$ DF = 34 mean square error = 0.7467
G_i = gasoline consumption (gallons) per capita in ith country
Pg_i = price of gasoline (SDRs per gallon)
C_i = cars per thousand

A slightly higher long-run price elasticity of demand for gasoline was obtained by regressing gasoline consumption per capita against the price of gasoline and national income per head, ie

$$\ln G_i = 4.66 - \underset{(3.2)}{0.91} \ln Pg_i + \underset{(12.4)}{1.13} \ln Y_i \qquad (22)$$

$\bar{R}^2 = 0.91$ DF = 34 mean square error = 0.6926

In this case, national income per capita acts as a proxy for the car population per head. However, when both income per capita and car population per head are included in the regression, then the problem of multicollinearity becomes severe, as can be seen below:

$$\ln G_i = 3.51 - \underset{(3.2)}{0.90} \ln Pg_i + \underset{(2.5)}{0.83} \ln Y_i + \underset{(0.9)}{0.24} \ln C_i \qquad (23)$$

$\bar{R}^2 = 0.91$ DF = 33 mean square error = 0.6938

In this equation, the strong correlation we know exists between car population per capita and income per head has resulted in less precise estimates of the separate effects of income and car population on gasoline consumption. Since we believe that both these explanatory variables have an effect on gasoline consumption, but know that these effects cannot be gleaned from the simple formulation due to multicollinearity, the answer appears to lie in the direction of a more complete specification of the relationships between income, car population, price of gasoline, and consumption of gasoline. A two-equation model can be formulated to capture the essence of these relationships, as follows:

$$\begin{aligned} \ln C_i &= a_0 + a_1 \ln Pcar_i + a_2 \ln Y_i \\ \ln G_i &= b_0 + b_1 \ln Pg_i + \ln C_i \end{aligned} \qquad (24)$$

In this recursive system of equations, the car population per capita is specified as a function of the price of cars and national income per capita, while gasoline consumption per capita is postulated to depend on the price of gasoline (the main variable affecting the utilization rate) and the stock of cars per capita. One is able to avoid the problem of multicollinearity by specifying a separate equation for the car stock in terms of income per head and the price of cars. From a practical point of view, the price of cars presents considerable difficulties, because it is well nigh impossible to obtain reliable data on a comparable basis for such a wide spectrum of countries. We have resorted to the use of a proxy for the price of cars in the form of taxes on acquisition and ownership of cars, but this was possible only for 24 countries out of the sample of 37.

The recursiveness of the equation system given by Equation (24) calls for estimation via a sequential use of ordinary least squares (OLS). Thus, the first equation is estimated using OLS (since the regressors are truly independent) and the predicted values of the dependent variable are subsequently used to form the regressor $\ln \hat{C}_i$ in the second equation, which is also estimated via OLS. The results of the estimation, with t values in parentheses, are as follows:

$$\ln C_i = -\underset{(7.8)}{5.1} - \underset{(3.0)}{0.4} \ln Pcar_i + \underset{(16.2)}{1.2} \ln Y_i$$

$\bar{R}^2 = 0.922$ SEE = 0.44

$$\ln G_i = -\underset{(2.4)}{0.4} - \underset{(3.5)}{1.3} \ln Pg_i + \ln \hat{C}_i \qquad (25)$$

$\bar{R}^2 = 0.322$ SEE = 0.611

The results seem to confirm our initial suspicion that multicollinearity was indeed a severe problem in the single-equation model above. The two-equation model yields sensible parameters that are statistically significant and have the anticipated signs. Moreover, the long-run price elasticity of demand for gasoline is higher than the equivalent single-equation estimates, while the long-run income elasticity of demand for cars suggests that the cars are 'luxury' goods. This last result is questionable as far as developed countries are concerned, given the role of saturation in car ownership at high income levels, but is quite plausible in a wider sample. Our proxy variable for the price of cars appears to have performed well, while the long-run price elasticity of demand for gasoline, at −1.3, suggests that gasoline demand is price elastic in the long run, though on a purely statistical basis, the elasticity is not significantly different from unity. The cross-section analysis provides further tentative evidence of the elastic nature of gasoline demand with respect to price in the long run, in addition to the evidence gleaned from some of the time-series country models estimated (see Table 2).

Conclusions

Of all the petroleum products, gasoline occupies today a position of pre-eminence due to its alleged price inelasticity of demand. Oil companies pursue gasoline sales because it is thought that gasoline represents the part of the crude oil barrel that is likely to suffer least from the ravages of crude oil price increases. Governments in oil-consuming countries load taxes on gasoline because it is thought to be a 'reliable' way of raising funds. Oil producer governments probably consider the transport sector to be the only one with a worthwhile claim on their wasting asset. In fact, all three actors on the oil stage share a common belief in the price inelasticity of demand for gasoline, both in the short and the long run.

While nobody would dispute that gasoline demand is inelastic in the short run (a year or two), this study casts doubts on the notion that it is so in the long run as well. The econometric results based on the time-series models suggest that the long-run price elasticity is not significantly different from unity in most cases, while the evidence – albeit tentative – from the cross-section model is that the truly long-run elasticity may well be above unity.

As has been demonstrated, there is no real need to resort to elaborate models involving *explicity* the changing stock of vehicles, its efficiency, and its use. Once due care and attention is paid to the special characteristics of gasoline demand, it is possible to determine what affects gasoline consumption, and track its course with a reasonable degree of accuracy, by employing an estimation technique that incorporates the implicit structure via restrictions on the parameters of the model. As a result of the use of this technique, the considerable inertia that gasoline consumption seems to possess is identified with lags in adjustment of the vehicle stock to its desired level. Moreover, as an experimental model for the USA would have it, there is some evidence that the duration of these lags is not fixed. Indeed, if one assumes that the speed of adjustment is a function of the real price of gasoline, the US case implies that the time lag has more than halved in the decade of the 1970s following the substantial real gasoline price increases. If these results are corroborated as far as other countries are concerned, the responsiveness of gasoline demand to changes in the real gasoline price is even greater than assumed generally, with of course even more profound consequences.

It cannot be emphasized too strongly that if the price elasticity of demand is well above unity in the long run and consumers do speed up their reactions to changed circumstances, then the oil companies – with investment plans to increase their ability to extract more of the lighter products from crude oil – and governments – with their policy of taxing gasoline heavily – and oil producers – with their belief that their precious asset should be reserved for 'premium' uses – could be in for a rude shock. The simple explanation for the higher than expected price elasticity of demand for gasoline is threefold: there are substitute types of transport fuels (diesel, liquified petroleum gas), there are substitute forms of transport, and of course consumers can spend their funds on activities or goods that compete with transport. Indeed, very few commodities are truly indispensible – given a long enough timespan, there are substitutes for most things.

References

1 J. Sweeney, *The Demand for Gasoline in the US: a Vintage Capital Model*, Workshops of Energy Supply and Demand, IEA, 1978.
2 Data Resources Inc, *A Study of the Quarterly Demand for Gasoline and the Impacts of Alternative Taxes*, Lexington, MA, 1973.
3 S. Wildhorn, B. K. Burright, J. H. Ennis and T. F. Kirkwood, *How to Save Gasoline*, RAND Corporation, R-1560-NSF, Santa Monica, CA, 1974.
4 H. S. Houthakker, P. K. Verleger and D. P. Sheehan, 'Dynamic demand analyses for gasoline and residential electricity', *American Journal of Agricultural Economics*, Vol 56, No 2, May 1974.
5 Charles River Associates, *The Effect of Automobile Fuel Conservation Measures on Automotive Air Pollution*, Cambridge, MA, 1975.
6 H. S. Houthakker and M. Kennedy, *The World Demand for Petroleum*, DRI, Lexington, MA, 1975.
7 J. B. Ramsey, R. Rasche and B. Allen, 'An analysis of the private and commercial demand for gasoline', *Review of Economics and Statistics*, Vol 57, No 4, 1975.
8 Federal Energy Administration, *1976 National Energy Outlook*, FEA, Washington, DC, 1976.
9 J. L. Sweeney, *Energy Policy and Automobile Use of Gasoline*, Stanford University, Stanford, CA, 1978.
10 R. Pindyck, *The Structure of World Energy Demand*, MIT Press, Cambridge, MA, 1979.
11 R. Archibald and R. Gillingham, 'A decomposition of the price and income elasticities of the consumer demand for gasoline', *Southern Economic Journal*, Vol 46, April 1981.
12 W. Wheaton, *The Long Run Structure of Transportation and Gasoline Demand*, unpublished, Department of Economics and Urban Studies and Planning, Massachusetts Institute of Technology, January 1981.
13 G. Fishelson, 'Demand for gasoline for usage by passenger cars', *Resources and Energy*, Vol 4, 1982, pp 163–172.
14 Z. Griliches, 'Distributed lags: a survey', *Econometrica*, Vol 35, No 1, January 1967.
15 C. R. Wymer, RESIMUL, SIMUL, ASIMUL, PREDIC, APREDIC, CONTINEST, TRANSF, DISCON Programmes, mimeographed manuals, IMF, Washington, DC.
16 J. L. Harrison, 'Small sample properties of selected distributed lag estimators', *International Economic Review*, Vol 11, No 1, February 1970.
17 L. M. Koyck, *Distributed Lags and Investment Analysis*, North-Holland, Amsterdam, 1954.
18 R. M. Solow, 'On a family of lag distributions', *Econometrica*, Vol 28, 1960, pp 393–406.
19 S. Almon, 'The distributed lag between capital appropriations and expenditures', *Econometrica*, Vol 30, January 1965, pp 178–196.
20 D. W. Jorgenson, 'Rational distributed lag functions', *Econometrica*, Vol 34, January 1966, pp 135–149.
21 E. L. Feige, 'Expectations and adjustments in the monetary sector', *American Economic Review*, Vol LVII, No 2, May 1967.

The long-run structure of transportation and gasoline demand

William C. Wheaton*

This article reports estimates of a cross national model for automobile ownership, fleet fuel efficiency, driving per vehicle, and as derived from these three, gasoline consumption. The model is a recursive system of equations derived by aggregating individual behavioral equations for the choise of a durable good and its usage. The results suggest that across countries, gasoline price differences exert themselves primarily by affecting the amount of driving, and not as time series studies show, through fleet fuel efficiency. The estimates also suggest that gasoline consumption is much more income elastic than it was previously thought to be and that most of this income effect derives from the impact of income on auto ownership.

1. Introduction

■ In the years since the 1973 oil embargo, there have been a growing number of efforts to model the demand for gasoline and its relationship to the underlying demand for transportation services. Such efforts are useful not only in forecasting the market response to rising fuel prices, but also as policy tools to evaluate the impact of regulations, such as Federal Fuel Efficiency standards. With only a few exceptions, all of these efforts have used time-series data for the preembargo period (1947–1972), primarily in the United States (CRA, 1975; DRI, 1973; Sweeney, 1978; Pindyck, 1979; Wildhorn *et al.*, 1974).

The reliance on time-series data raises two important questions about the accuracy and reliability of the results of these models. First, during the preembargo period, real income rose slowly and real fuel prices fell gradually in a manner that was highly correlated. Can the models, therefore, separately estimate income and price effects? Second, during this same period, there was little absolute change in the real price of gasoline. Can such models, therefore, be relied upon to forecast truly long-run responses to major changes in price or income?

An alternative approach to estimating models of the demand for gasoline and transportation services is to introduce some cross sectional variation into the sample data. If, for example, one includes subarea disaggregation within the United States, income variation is obtained which is largely independent of fuel prices. The latter, however, will still exhibit little absolute variation. In fact, to get large scale price variation during the preembargo period, one must compare different countries. Unfortunately, the cross national studies (Houthakker and Kennedy, 1979) and the cross state studies within the United States (Greene 1979) use reduced-form models in which gasoline demand is predicted directly with no consideration of transportation services. The strength of the time-series models is that they estimate separate income and price effects for vehicle ownership, vehicle characteristics, and vehicle usage. Gasoline demand is then derived from a well-known identity relating these three components.

It is interesting that neither group of studies has investigated the possibility that structural relationships might exist among the different transportation components (own-

* Massachusetts Institute of Technology.

ership, driving, vehicle efficiency). The cross sectional models estimate only the demand for gasoline, and although the time-series models have developed equations for each transportation component, the equations contain only exogenous variables, such as income and prices. A full structural model would permit inferences about the impact that regulating one endogenous variable (for example, fuel efficiency) would have on the others.

The objective of this study, then, is to improve upon this research in the ways discussed above. First, a long-run model will be estimated, cross nationally, to obtain parameters for a sample with maximum independent variation in income and prices. Second, the model will also be structurally disaggregated, not only to predict separately vehicle ownership, driving, and fuel efficiency, but also to make some preliminary assessments about possible relationships among these endogenous variables.

The results of the model contrast with the previous research in several important ways. The aggregate gasoline consumption elasticities are reasonably comparable, but the structure of demand differs considerably. The time-series studies suggest that in the long run the impact of price occurs mostly through improved fuel efficiency (smaller cars) and, to a lesser degree, lower ownership rates. The cross national estimates say quite the contrary, that in the long run most of the overall price elasticity comes from reduced usage of each vehicle. The results also suggest (for the first time) that ownership rates have a strong influence on vehicle usage, but fuel efficiency does not. Finally, the cross national model estimates include some highly elastic income effects, which indicate that reductions in aggregate fuel demand may be difficult, particularly in rapidly growing Third World countries.

As a note of caution, it would be prudent to point out that as is typical with most cross national research, the quality of the data used in the study is less than ideal. The results of the model, therefore, should perhaps be regarded more as pedagogical than definitive: cross national models can be estimated, and the estimates yield conclusions that seem to differ from those of models estimated using intracountry time series.

The article is organized as follows. Section 2 discusses the specification of the model and reviews some studies from the existing time-series literature. Section 3 discusses the data, and Section 4 presents a number of statistical results. Finally, Section 5 examines some implications of the research.

2. The derived demand for gasoline

■ Almost all time-series models of gasoline consumption estimate a derived demand equation by using an identity, such as (1):

$$CON = (AUTO \times DIST)/MPG, \tag{1}$$

where

CON = consumption of fuel per capita;

$AUTO$ = vehicles or automobiles per capita;

$DIST$ = use of each vehicle (miles per year); and

MPG = average fleet fuel efficiency.

With this identity, demand equations are estimated separately for each component ($AUTO$, $DIST$, MPG), and then overall fuel consumption is derived by applying the identity. Since (1) is log linear, any elasticity of CON is simply the sum of the three component elasticities. Thus, with respect to gasoline price (P), the following relationship applies:

$$E_{CON,P} = E_{AUTO,P} + E_{DIST,P} - E_{MPG,P}. \tag{2}$$

There are a number of advantages to estimating component demand equations, and

167

not simply estimating gasoline demand directly. First, and most obviously, one may be interested in *how* income and price affect gasoline consumption, and not simply in the magnitude of the effect. The distributional or other consequences of improved fuel efficiency versus, say, reduced auto ownership might be of interest. Second, it is sometimes believed that disaggregate models have a higher level of parametric stability. This is due to the fact that disaggregation may often suggest new exogenous variables, which are important predictors in each component equation. Last, disaggregation may also be important if structural relationships exist among the endogenous variables.

The issue of what kind of structural model might underlie the joint demand for gasoline and transportation has yet to be discussed in the time-series literature on the subject. Existing models have simply assumed that the three demand components are determined simultaneously, and then have estimated the equations for each in reduced form. In fact, however, there is a growing body of microeconomic theory about durable goods and their usage, which is highly applicable to the question at hand. Consumer decisions about the type and number of vehicles to purchase (*AUTO, MPG*), and then about how much to use each vehicle (*DIST*), would seem to conform very well to a microeconomic model proposed originally by Heckman to analyze labor force participation and the decision about hours of work. The former is a discrete choice, and the latter is a continuous demand function *conditional* on the original discrete choice. Since Heckman's work, similar models have been applied to the housing market (choice of tenure and then housing consumption) by Lee and Trost (1978) and most recently to electricity consumption (choice of appliance and then power usage) by McFadden and Dubin (1982). In all of these cases, the consumer's decision about the choice of durable good and its usage is considered to occur simultaneously. Statistically, however, the usage equation is estimated conditional upon the choice of the good. This allows one to make statements about how the choice of good may structurally affect its usage.

Applying this model to transportation services, a household may be perceived as choosing first among a set of n alternative portfolios of automobiles. Each portfolio i is characterized by a set of attributes Z_i, which includes the number of vehicles and their fuel efficiency ($AUTO_i$, MPG_i). The probability of selecting portfolio i, P_i will then depend on a vector of exogenous variables W (such as income, prices), parameters α, and the sets of attributes of the n portfolios $Z_1, \ldots, Z_n$:

$$P_i = F_i(Z_1, \ldots, Z_n, W, \alpha) \quad i = 1, \ldots, n. \tag{3}$$

Given that a particular choice i has been made, there exists a conditional usage or driving demand equation, which will depend on the exogenous variables W and an error term ϵ. This may be represented in (4) below. Rather than estimating a set of n such conditional driving equations, the model may be simplified to estimate a single driving equation, but one in which the amount of driving depends on the attributes of the chosen portfolio. In this way *driving* still occurs conditional on the portfolio choice, but the conditioning is represented by using a single equation. This is shown in (5).

$$DIST = D_i(W, \epsilon) \quad i = 1, \ldots, n \tag{4}$$

$$DIST = D(Z_i, W, \epsilon). \tag{5}$$

Although the choice of automobile portfolio and the decision about *DIST* occur at the same time, statistically it is a conditional demand equation that is estimated for *DIST*. This has raised considerable interest about whether the error term in (5) will be correlated with the Z_i. If, as seems likely in some situations, ϵ is correlated with the choice probabilities, then it will be correlated with the variables in Z, and OLS estimates of (5) will not be consistent. McFadden (1982) suggests applying a specification test to the Z variables in the usage equation, and if necessary, using either *FIML* to estimate the combined system (3)–(5) or instrumental variables on (5) alone.

164

The macro characteristics of a country's automobile fleet as well as its aggregate vehicle usage may be thought of as the outcome of the individual decisions made according to (3)–(5). Although it is impossible to derive analytically the aggregate demand schedules, a heuristic argument suggests using a set of equations similar to (3)–(5) at the macro level. First, if the choice probabilities are aggregated across individuals, one would arrive at a countrywide frequency distribution over the set of automobile portfolios. The first moments of this distribution with respect to the variables *AUTO* and *MPG* will be expected values for countrywide auto ownership and average fleet fuel efficiency. These expected values will be functionally related not just to the mean values of W but to the full distribution of W in the population. Still, as is often done in demand studies, one might use as approximations equations containing only means of the vector of exogenous variables W. In a similar way, individual decisions about driving, in equation (5), can be aggregated to yield a macro driving equation. Although this equation would depend on much more than the country-average values of Z and W, an equation including only the latter could serve as an approximation. Thus, in the case where the portfolio characteristics Z are described by *AUTO* and *MPG*, a set of aggregate equations, such as (6)–(8) below, might be estimated:

$$DIST = D_1(AUTO, MPG, W, \epsilon_1) \tag{6}$$

$$AUTO = D_2(W, \epsilon_2) \tag{7}$$

$$MPG = D_3(W, \epsilon_3). \tag{8}$$

Since the aggregate equations are not analytically derived, one cannot say in advance whether the likely correlation between the error terms at the micro level will continue to exist in the aggregate equations. At this point, it is an empirical question, which should be resolved with a specification test (Hausman, 1978).

TABLE 1 Major Gasoline Demand Studies

	Pindyck (1979)[1]	Sweeney (1978)[2]	Wildhorn *et al.* (1974)[2]	CRA (1975)[3]	DRI (1973)[2]
Gasoline Price Elasticity					
Long-run total cons:	−2.07	−.78	−.78	−1.37	−.23
Driving:		−.06	−.36		
Ownership:	−.64		−.25		
MPG:	1.43	.72	.17		
Short-run total cons:	−.37	−.22	−.26	−.28	−.07
Driving:		−.22			
Ownership:	−.26				
MPG:	.11	.01			
Income Elasticities					
Long-run total cons:	.96	.82	.88	.06	.94
Driving:	.66	.82			
Ownership:	.30		.88		
MPG:					
Short-run total cons:	.18		.18	.012	.28
Driving:	.06				
Ownership:	.12				
MPG:					

[1] Eleven Western countries, pooled 1955–1973 time series.
[2] U.S. National time series, 1950–1973.
[3] 7-region pooled U.S. time series, 1950–1973.

170

Although none of the existing time series studies of gasoline demand has applied this more structural model, those studies have produced an interesting set of reduced form income and price elasticities. For ease of comparison, these are summarized and presented in Table 1. In reviewing these studies, three conclusions seem to emerge.

(1) With the exception of the CRA report, the studies are in general agreement in their estimates of long-run gasoline income elasticities. But they disagree about the long-run price elasticity of gasoline demand. The income effects are always slightly inelastic, while the price effects vary widely.
(2) There is little agreement among the studies about how the income and price effects apply to each of the transportation components. The Wildhorn *et al.* research (1974) suggests that gasoline price exerts most of its influence through driving, while the Pindyck (1979) and Sweeney (1978) studies find it occurs mostly through fleet fuel efficiency. Wildhorn *et al.* find that income influences ownership most, while Pindyck concludes that income exerts its influence primarily on driving.
(3) In most of the studies, the income and price effects are rarely *both* significant in the equation for any particular determinant of gasoline demand. If *MPG*, for example, has a strong price elasticity, then it has a weak income elasticity and *vice versa*. This suggests that the preembargo time series has a sufficiently strong common trend in the price and income data to make the separate estimation of each elasticity quite difficult. In a number of the studies, the equations for each component do not even include both income and price variables; one of the two variables is dropped from the equation, despite there being little theoretical justification for doing so. Estimates of one elasticity without the other variable being in the equation would have to be regarded quite cautiously.

3. Cross national data

■ In developing a cross national model, particular attention must be paid to the sources and reliability of data. Different countries may use different definitions or accounting systems, so that comparability can become a serious problem—at least in principle. To minimize these problems, the cross national data collected for this study used the same definitions and measurement standards as the U.S. time-series data. With these definitions, a full set of data was obtainable for 42 countries. The measurement of one variable, fleet fuel efficiency, was however, considered to be more reliable for 25 of these countries than for the others. For this reason, separate models were estimated for both the 25- and the 42-country samples. In all cases, the data were collected for the year 1972, the most recent period before the effects of the oil embargo.

The data on per capita income were obtained from annual World Bank Statistics and presented no problem. There has been, however, considerable recent discussion about the meaning of cross national income comparisons. Kravis (1978), in particular, has argued that the prices of many goods and services vary systematically among countries, and on the basis of a study of 16 nations, he has constructed a cross national GNP deflator. The problem with applying this deflator, however, is that the 16 countries researched by Kravis do not overlap with those used in many studies, including this one. To make the deflator available for more countries, Kravis has used a statistical analysis of the original 16-nation sample to estimate the deflator for over a hundred additional countries. In the 42-country sample used in this study, however, the simple correlation between this predicted deflator, and GNP per capita, is .98. Thus, it is doubtful that the index will add much to the equation, although it would still be instructive to estimate the model in both nominal and deflated dollars.

Ideally, the prices used in a gasoline demand model should include not only the price of gasoline but also the prices of the vehicles that use gasoline. In the case of gasoline prices, the U.S. Bureau of Mines conducts an annual survey of retail (pump) prices in

171

75 countries. Developing a comparative price index for automobiles, however, is more difficult.

In the process of developing the GNP deflator, Kravis constructed an automobile price index. It appropriately considered, first, the average difference across countries in manufacturing prices, controlling for quality and variation in fleet mix, and second, differences across countries in automobile registration fees, excise taxes, and import duties. Unfortunately, this price index has not been extended beyond Kravis' original 16-nation sample.

To enable construction of a more simple auto price index that would apply to the 42-country sample used in this research, the Motor Vehicle Manufacturers Association provided a detailed survey of the taxes, fees, and import duties that apply to automobiles in each country. After adding the major fees, sales or V.A.T. taxes, and import duties, a price variable was constructed which represents the comparative cost to a consumer in each country of a world-traded automobile.

Unfortunately, such a price index is appropriate only for widely traded vehicles, and many countries assemble cars that are not traded. This is particularly true in the developing nations where there often exist licensed assembly plants. Such "local assemblies" are not taxed as imports, and they often constitute a large part of the vehicle fleet. It was simply beyond the scope of this research to do the extensive, primary source investigation necessary to determine the prices of such nontraded vehicles. As a consequence, the automobile price variable used here reflects only those differences between countries that are due to tax and import policy.

The consumption of gasoline in each country is available from the U.S. Bureau of Mines in the same publication as the data on gasoline prices. To match the data on gasoline, one would ideally want information on the stock of gasoline consuming vehicles. Current sources, however, record data in only two categories: all automobiles (including taxis), and buses and trucks. Since some automobiles may be diesel powered, while some trucks are gasoline powered, using either only the first category or the sum of the two categories may introduce a bias.[1]

The final measurement issue is the most important—determining either fleet fuel efficiency or the number of miles driven by each vehicle. Using the identity (1), only one of these needs to be estimated, and two approaches are possible. First, one can obtain an independent estimate of vehicle miles driven from, for example, surveys or toll receipts. Dividing gasoline consumption per vehicle by this driving figure produces an estimate of actual fleet fuel efficiency. Second, an independent estimate of fleet fuel efficiency can be constructed by averaging data on the designed fuel consumption of different makes and models. Dividing fuel consumption per vehicle by this measure of fleet efficiency yields an estimate of miles driven per vehicle.

For this study, the fuel efficiency of the fleet in each country was estimated by applying the second of these two methods. To do this, data were first obtained on vehicle sales, by model, for as many years as possible. Unfortunately, the data for most countries are available in published form only back to 1970 (MVMA). Before then, the information for all but a few countries must be obtained directly from the manufacturers. Since the sales of automobiles between 1970 and 1972 constituted at least 40% of the fleet in most countries, the characteristics of these additions to the stock should be quite indicative of the 1972 stock as a whole. In the United States, for example, the estimated efficiency of the fleet went from 14.42 in 1962 to 13.57 in 1972. Using the vehicle age distribution, the average efficiency of the subpopulation of 1970–1972 vehicles in the United States would have been only 3% different from that of the fleet as a whole.

[1] It should be pointed out that the U.S. data on the vehicle fleet are also not differentiated by use of fuel, and the time-series studies have also had to use either all automobiles or all vehicles.

172

To estimate the fuel efficiency for each make or model of automobile sold, average city-driving EPA data for the years 1974 were obtained for each model of car sold in the United States (EPA). These figures were then increased by 10% to account for the lower fuel efficiency of the more recent American exhaust emission systems. Finally, a nonlinear regression equation was estimated relating these factored EPA figures to engine displacement (R^2 = .89), and this was used to predict the efficiency of automobile models not sold in the United States.

For 25 countries, very detailed data were available on the make and model of automobiles sold during the years 1970–1972. For these nations, weighting up the fuel efficiencies of each model produced a reasonable estimate for the efficiency of the fleet. In 17 additional countries, similar sales data were obtained, but not always by model—sometimes only by manufacturer. These less detailed data produced estimates for those countries which were not likely to be as accurate as the estimates for the 25-country sample.[2]

The issue of driving conditions raises a final consideration about whether the specification of the model should not include some geographic or other noneconomic variables that might influence transportation demand. Greene's cross state study (1979) suggests such factors could be important, although the theoretical arguments advanced often yield rather ambiguous hypotheses. For example, holding population constant, greater land area or lower population density certainly influences the distances people have to drive, if they choose to drive at all. If, however, they choose not to make as many trips, or to use other modes, then larger land area might not have any effect. Similarly, it is sometimes believed that auto ownership and vehicle characteristics are different in urban than in rural areas. Holding income and prices constant, should the level of urbanization increase vehicle ownership? Urbanization certainly increases trip making, but it also increases the opportunity for travel on public transportation. In short, it is hard to make rigorous theoretical arguments for such variables. To be as comprehensive as possible, though, the share of the population that lives in urban areas (*URBAN*) is included in the *AUTO* and *MPG* equations, while the land area of the country (*AREA*) is included in the driving equation.

In summary, the collection of available cross national data raises three issues, which can be addressed when estimating parameters of the model. First, any bias that might be introduced by the lack of information on the gasoline consuming fleet can be at least partially studied by estimating the equations using alternatively the automobile fleet and then the total vehicle fleet. Second, the model can be estimated in both nominal dollars and real dollars to test the importance of comparative prices and the usefulness of the Kravis deflator. Third, the model can also be estimated for two samples, which vary somewhat in the quality and level of detail with which the fleet efficiency variable was calculated. This will provide at least some indication about how sensitive the results are to the measurement of this important variable. The final data for the 25- and 42-nation samples are reported in Appendices A and B.

4. Statistical results

■ In estimating the cross national model, both a linear and a log-linear specification were tried, and a Box-Cox test was applied to choose between the two. The results of the procedure suggested that the log-linear form was superior for the overall consumption, vehicle ownership, and driving equations, but that the linear form was better for the *MPG* or fuel efficiency equation. In many respects, these results are consistent with *a priori*

[2] It should also be pointed out that although these procedures assume that "EPA city driving" characterizes operating conditions around the world (Owen, 1973), all of the existing estimates of fleet efficiency are based on the assumption of fixed operating conditions as well.

expectations. As income per capita falls toward zero, for example, automobile ownership and driving must do likewise. Fuel efficiency, on the other hand, is at least somewhat technologically constrained. Thus the fuel efficiency equation should have a positive intercept, while the equations for driving and ownership need not. The statistical results merely reaffirm this intuition, and hence linear equations are reported for *MPG*, while log-linear forms are used for *AUTO* and *DIST*.

The first set of equations represents a sort of "base" model, in which the sample consists only of those 25 nations with the most reliable data. The equations in the "base" model are estimated by using only the automobile fleet and without deflating income or prices by the Kravis price index. This was the model in which the statistical specification issue was studied.

Answering the question of whether OLS is appropriate for estimating the driving equation involves testing whether possible correlation among the error terms in the three equations has created a correlation between the error term in the *DIST* equation and the variables *AUTO*, *MPG*. Assuming that some set of instruments exists which identifies the equations, a specification test can be applied by including *AUTO*, *MPG* and the residuals from their reduced-form equations in the *DIST* equation. If the residuals are significant, OLS assumptions are violated. In the case at hand, the price of automobiles (*TAX*) and the level of urbanization (*URBAN*) were assumed to be the identifying instruments for *AUTO* and *MPG*, while land area (*AREA*) entered only the driving equation. It is obvious that income and the price of gasoline should enter all of the equations. With this partitioning of the instruments, the results of the specification test were insignificant: the OLS assumptions were found to hold. Several alternative ways of assigning the three instruments (*TAX*, *URBAN*, *AREA*) were also tried, and in each case a resulting specification test also proved insignificant. It should be mentioned that the three instrumental variables actually have little explanatory power in the model. Income and gasoline prices totally dominate the equations. With such weak identifying instruments, the results of the specification tests should perhaps be regarded cautiously. On the other hand, without any additional variables, one can only conclude that OLS is justified, and hence it is the OLS results that are reported here.

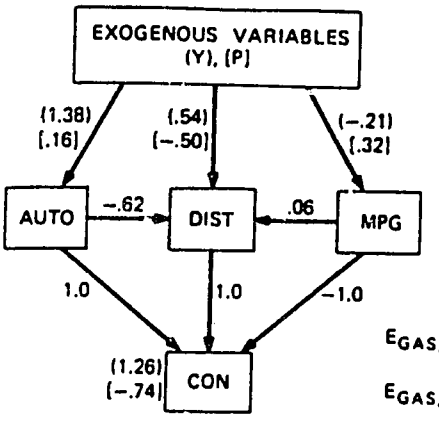
In the first equation, that for automobile ownership, income is the only significant predictor, and it has a distinctly elastic effect. Neither the price of gasoline nor the opportunity price of imported automobiles (*TAX*) has any significant influence on the size of the automobile fleet. The level of urbanization is insignificant as well. In the second equation, that for fuel efficiency, there are more balanced income and price effects. When the *MPG* elasticities are computed at the sample mean values, that for income is −.21, while that for gasoline price is .32. Both of these are highly significant statistically. The negative income effect suggests that greater wealth does indeed lead to a demand for larger (less fuel efficient) automobiles. On the other hand, the price of automobiles, at least as measured by the opportunity cost of imports, exerts no influence on fleet fuel efficiency, and the level of urbanization is also insignificant. It is important to note at this point that the gasoline price elasticity of fuel efficiency is quite small in comparison with the estimates in the more recent time-series studies.

The results of the driving equation contain a number of interesting implications as well as some surprises. The first of these is that geographic land area plays no role in determining driving behavior—the equation is completely determined by economic variables and vehicle characteristics. Among the former, the income and price effects are significant statistically, although inelastic in magnitude. What are most interesting, perhaps, are the signs and magnitudes of the coefficients of the structural variables *MPG*, *AUTO*. Greater fuel efficiency seems to induce no additional driving, but greater auto

174

FIGURE 1

DECOMPOSITION OF DEMAND ELASTICITIES



$$E_{GAS,Y} = E_{AUTO,Y}(1+E_{DIST,AUTO}) + E_{DIST,Y} + E_{MPG,Y}(-1+E_{DIST,MPG})$$

$$E_{GAS,P} = E_{AUTO,P}(1+E_{DIST,AUTO}) + E_{DIST,P} + E_{MPG,P}(-1+E_{DIST,MPG})$$

ownership substantially reduces the use of each vehicle. Driving is indeed quite conditional upon at least the size of the automobile fleet.

The estimated system of three equations, for *LAUTO*, *MPG*, and *LDIST*, is depicted in Figure 1. Here all of the income and price elasticities are displayed, as well as the structural relationships among the endogenous variables. At the bottom of the figure are

TABLE 2 25-Country Sample, Undeflated, Automobile Fleet

	Equation			
Variable	*LAUTO*[1]	*MPG*	*LDIST*	*LCON*
C	−13.2	22.2	6.2	−2.11
	(−8.60)	(7.67)	(3.70)	(−1.98)
PGAS	.162	.141[2]	−.500	−.700
	(.93)	(6.28)	(−3.98)	(−4.81)
Y	1.375	−.00269[3]	.537	1.22
	(9.01)	(−6.24)	(3.76)	(12.04)
TAX	.366	−.708		.0501
	(1.31)	(−.926)		(.289)
MPG			.063	
			(.384)	
AUTO			−.615	
			(−5.92)	
URBAN	−.581	2.47		−.452
	(−1.45)	(.913)		(−1.64)
AREA			.0147	.0482
			(.586)	(1.50)
R^2	.887	.821	.887	.938

[1] *L* represents a log-linear equation where parameters are elasticities. Other equations are linear. The *t*-statistics are in parentheses.

[2] Elasticity at mean sample values = .32.

[3] Elasticity at mean sample values = −.21.

the elasticity definitions showing how the component elasticities aggregate into the overall income and price elasticities of gasoline consumption. Summing these component effects, one obtains an overall income elasticity of 1.26, and an overall price elasticity of −.74. The final equation in Table 2 demonstrates that a simple reduced form gasoline demand equation produces almost identical aggregate elasticities (1.22 and −.70 respectively).

In summary, then, the base model yields four important conclusions. First, long-run gasoline demand is income elastic and only somewhat price inelastic. Second, almost all of the income effect occurs directly through its impact on automobile ownership. Third, the effect of gasoline price occurs exclusively through fuel efficiency and driving, with the latter effect being almost twice that of the former. Finally, auto ownership exerts a strong structural effect on driving, but fuel efficiency does not. Some implications of these results are discussed further in the next section. What is important here is to ascertain whether these conclusions are robust to different samples and variable definitions.

The first test of the model is to reestimate it using deflated income and prices. The results are reported in Table 3, and when compared with Table 2, there are no important differences. In the automobile equation, the income elasticity increases from 1.38 to 1.89, since deflating reduces the sample variation in "real" income. The price effects, however, remain insignificant. In the *MPG* equation, the coefficients change, because the equation is linear. The elasticities computed at the sample means remain essentially the same. In the *LDIST* equation, there is again no significant change, and the overall consumption

TABLE 3 25-Country Sample, Deflated, Automobile Fleet

	Equation			
Variable	*LAUTO*[1]	*MPG*	*LDIST*	*LCON*
C	−17.0 (−4.93)	23.3 (5.81)	6.91 (3.96)	−1.92 (−.86)
PGAS	.0252 (.128)	.0913[2] (4.86)	−.541 (−4.37)	−.801 (5.56)
Y	1.89 (5.36)	−.0019[3] (−2.12)	.456 (2.41)	1.25 (5.34)
TAX	−.054 (−.242)	−.581 (−1.27)		−.148 (−1.03)
MPG			.103 (.240)	
AUTO			−.573 (−6.26)	
URBAN	−.54 (−1.21)	2.93 (.81)		−.37 (−1.24)
AREA			.71 (.30)	.04 (1.19)
R^2	.854	.702	.881	.932

[1] *L* represents a log-linear equation where parameters are elasticities. Other equations are linear. The *t*-statistics are in parentheses.

[2] Elasticity at sample means = .33.

[3] Elasticity at sample means = −.20.

176

equation exhibits very similar aggregate elasticities. Thus, whether nominal or "Kravis deflated" dollars are used seems to make almost no difference in the results of the model.

The second test is to examine the implications of using the fleet of automobiles as a proxy for the fleet of gasoline consuming vehicles. To do this, the model is reestimated using all vehicles (including trucks and buses). While this is only an approximation to the gasoline fleet, its bias is different from that introduced by using only automobiles. Since fuel efficiency data were available only for automobiles, the *MPG* equation remains the same, and automobile rather than total vehicle efficiency is used in the vehicle driving equation. The overall reduced-form gasoline equation is also the same, and so it is not reestimated either. In Table 4, then, the results for a vehicle (rather than automobile) ownership equation are presented, along with a structural equation for miles driven per vehicle. In all equations, the elasticities, significance levels, and R^2 values are extremely similar to those in Table 2. Since it makes little difference whether the model is estimated in terms of vehicles or automobiles, it would seem doubtful that an exact measurement of the gasoline-consuming fleet would change the results either.

The final test of the model involved estimating the base equations (those with the automobile fleet and undeflated income) for a larger sample of 42 nations. In addition to the countries in the original sample, this larger sample included primarily a number of poorer, less developed countries, for which the measurement of fleet fuel efficiency was not so precise. The results are in Table 5, and with only a few exceptions the coefficients are not significantly different from those of the base model. The main difference is that

TABLE 4 25-Country Sample, Total Vehicles, Undeflated

	Equation	
Variable	*LVEH*[1]	*LDIST*
C	−11.3 (−9.15)	6.37 (3.98)
PGAS	.099 (.674)	−.483 (−3.83)
Y	1.19 (9.89)	.525 (3.54)
TAX	.309 (1.27)	
MPG		−.017 (−.038)
VEH		−.578 (−4.69)
URBAN	−.27 (−.81)	
AREA		−.0018 (−.068)
R^2	.882	.804

[1] *L* represents a log-linear equation where parameters are elasticities. Other equations are linear. The *t*-statistics are in parentheses.

177

TABLE 5 42-Country Sample, Undeflated, Automobile Fleet

	Equation			
Variable	*LAUTO*[1]	*MPG*	*LDIST*	*LCON*
C	−13.4 (−9.22)	21.9 (10.7)	8.47 (4.75)	−.391 (−.590)
PGAS	.132 (.627)	.122[2] (6.15)	−.547 (−3.89)	−.94 (−4.97)
Y	1.43 (9.6)	−.0023[3] (−5.58)	.328 (2.38)	1.16 (9.9)
TAX	.114 (.34)	−.567 (−.531)		−.369 (−1.47)
MPG			.057 (.158)	
AUTO			−.417 (−5.18)	
URBAN	−.22 (−.72)	3.8 (2.02)		.032 (.13)
AREA			−.518 (−2.05)	−.036 (−.93)
R^2	.914	.69	.742	.94

[1] *L* represents a log-linear equation where parameters are elasticities. Other equations are linear. The *t*-statistics are in parentheses.
[2] Elasticity at sample means = .26.
[3] Elasticity at sample means = −.12.

the income elasticity of *MPG*, while still very significant, is about two-thirds of its value in the 25-nation sample. It is interesting that some of the geographic variables become significant for the first time in this larger sample, although this has no effect on the other coefficients.

As a consequence of these experiments, it does seem safe to assert that the data collected in this research contain a set of strong underlying relationships which continue to hold when the sample is substantially changed, when variable definitions are altered somewhat, and when the model is estimated with and without deflating by the only available world price index.

5. Conclusions

■ The results of the cross national model contain some important implications, first, for our understanding of the long-run structure of transportation and gasoline demand, and second, regarding the possible effectiveness of different regulatory policies designed to reduce the consumption of gasoline. Each of these issues is briefly discussed below.

□ **Gasoline and transportation demand.** The models estimated in the previous section give a consistent picture of gasoline demand, first, as being influenced exclusively by economic and not geographic factors, and second, as being more income than price elastic.

178

The income elasticity of overall consumption is always greater than unity, while the price elasticity is always less than one. The implications of this, for much of the developing world, are important. In the decade since the formation of OPEC, real per capita incomes in much of the Third World have risen by not that much less than the *real* rise in the price of oil. If the income elasticity of demand for gasoline is 1.2, while the price elasticity is −.7, and if these price/income trends were to continue, then it might be difficult for the Third World to reduce its per capita consumption of gasoline.

The strong effect of income on gasoline consumption occurs almost exclusively through its influence on the level of automobile ownership. Income may also influence the amount each vehicle is driven, but the concomitant increase in auto ownership cancels this by reducing vehicle usage. The sum of these two effects exactly offsets a small negative influence of income on fuel efficiency. Thus, for the rapidly developing nations to reduce their consumption of gasoline, it would seem important somehow to stem the rapid growth in auto ownership.

In contrast to the effect of income, the influence of price in the model is limited to improvements in fuel efficiency and reduced driving. Unlike the results in several time-series studies, gasoline prices are found to exert no influence on automobile ownership. The sum of the effects on fuel efficiency and driving, however, is still quite strong. Perhaps most importantly, the price effect through reduced driving is much greater than the price effect on fleet composition or fuel efficiency. The relatively small price elasticity of fuel efficiency and the higher one for driving again stand in sharp contrast to most of the recent time-series research.

The final point that deserves discussion concerns the lack of any effect on auto ownership or fuel efficiency from the price of vehicles. Since the *TAX* variable refers only to new vehicles, the results of the model imply that higher new car prices lead consumers to maintain their older cars longer. This conclusion is consistent with the Pindyck study, for example, where new car prices were found to decrease both new car sales and the rate of depreciation, by identical amounts. The sum of these two effects yields a steady-state size of the fleet that is invariant to prices of new cars.

□ **Regulatory effects.** It is tempting to consider the results of this research in light of current regulatory efforts, especially within the United States, to reduce gasoline consumption. Such extrapolation of the results, however, is probably not justified since the Energy Policy Conservation Act requires major shifts in technology, not simply the forced consumption of smaller cars. The cross national results suggest only that as gasoline prices rise the shift to smaller cars is relatively modest. Similarly, given some exogenous shift to smaller cars, little additional driving in each car can be expected. How consumers respond to technological improvements in fuel efficiency, for cars of given size, could be another matter.

The major regulatory conclusion, which does emerge from the model, and might seem appropriate to the contemporary context, is the impact of possible reductions in automobile ownership. It is important to recall that the model, first of all, suggests that such reductions would be difficult to achieve by using price policy. Neither vehicle prices nor fuel prices seem to influence the size of the fleet. Assuming, however, that some policy could achieve reductions in the fleet, the cross national model says that this, in turn, would not be very effective in reducing fuel consumption. If the fleet, for example, were to be cut in half, the driving per vehicle would increase by almost 60%, leading to a reduction in the initial level of fuel consumption of only 20%. Such a policy might indeed involve a lot of effort and hardship, in exchange for a relatively modest reduction in fuel consumption.

179

Appendix A

■ Data for the 25-nation sample appear in Table A1.

TABLE A1 25-Country Sample

Country	*AUTO*[1]	*MPG*[2]	*DIST*[3]	*PGAS*[4]	*Y*[5]	*TAX*[6]	*PRICE*[7]
Argentina	.077	25.8	20.4	26	1053	2.11	.52
Australia	.356	25.4	15.4	26	2947	1.72	.88
Austria	.197	27.5	11.5	63	1922	1.18	.78
Brazil	.032	28.5	25.1	38	501	3.30	.45
Canada	.347	16.9	16.4	41	3884	1.27	.99
Denmark	.244	26.5	11.8	76	3159	1.18	.91
Finland	.177	28.5	23.0	71	2251	2.40	.74
France	.271	30.5	10.0	85	2775	1.33	.82
W. Germany	.268	27.5	10.1	80	3155	1.11	.86
Greece	.034	30.5	25.9	82	1134	1.05	.61
Ireland	.141	29.0	15.9	70	1326	1.35	.65
Italy	.232	31.5	8.4	102	1727	1.35	.73
Japan	.120	34.0	15.2	75	1980	1.24	.69
Mexico	.030	25.0	34.7	27	661	2.05	.54
Netherlands	.222	29.5	11.2	79	2429	1.34	.82
Portugal	.076	31.5	9.3	86	715	2.20	.55
Spain	.095	31.5	10.3	65	1089	1.81	.57
Sweden	.305	25.0	9.7	82	4109	1.21	.99
Switzerland	.256	28.0	14.2	72	3349	1.13	.92
U.K.	.235	27.5	10.7	69	2195	1.26	.73
U.S.A.	.472	14.8	13.6	40	4789	1.07	1.00
Uruguay	.052	29.0	16.8	69	927	2.98	.50
Venezuela	.075	20.5	28.6	17	1101	4.50	.56
Belgium	.229	28.5	10.5	82	2900	1.25	.89
S. Africa	.072	26.0	17.2	46	950	1.60	.58

[1] Autos per capita.
[2] Fleet fuel efficiency (miles per gallon).
[3] Average miles per automobile (annual, in thousands).
[4] Gasoline price (U.S. cents).
[5] Income (dollars).
[6] One plus local tax rates and import duty rates.
[7] Kravis price index.

180

Appendix B

■ Data for the 42-nation sample appear in Table A2.

TABLE A2 **42-Country Sample**

Country	*AUTO*[1]	*MPG*[2]	*DIST*[3]	*PGAS*[4]	*Y*[5]	*TAX*[6]	*PRICE*[7]
Ceylon	.007	29.0	12.3	65	117	1.50	.39
Dom. Repub.	.012	26.0	42.1	48	366	2.30	.46
El Salvador	.011	28.5	25.2	54	298	2.55	.43
Ethiopia	.0017	29.5	21.2	85	72	2.20	.38
Ghana	.006	29.5	38.3	43	257	1.61	.41
India	.0013	26.0	17.8	68	105	2.90	.34
Iran	.01[illegible]	27.0	16.2	33	388	3.35	.41
Israel	.069	27.0	25.3	60	1919	1.55	.72
Jamaica	.052	26.0	17.6	39	768	2.02	.53
Kenya	.013	30.0	13.7	60	143	2.10	.41
Lebanon	.066	26.5	23.4	43	603	1.68	.52
Morocco	.016	30.0	13.3	75	224	2.20	.42
Norway	.22	27.0	10.6	85	2882	1.20	.88
Pakistan	.0025	31.0	23.5	47	175	2.95	.40
Paraguay	.0075	27.0	33.2	58	259	1.54	.42
Tunisia	.016	30.0	12.1	83	289	2.19	.43
Turkey	.0047	26.5	51.7	48	367	1.94	.42

[1] Autos per capita.
[2] Fleet fuel efficiency (miles per gallon).
[3] Average miles per automobile (annual, in thousands).
[4] Gasoline price (U.S. cents).
[5] Income (dollars).
[6] One plus local tax rates and import duty rates.
[7] Kravis price index.

181

References

Automobile International. New York: Johnson Publishing, 1972.

World Automotive Market. New York: Johnson Publishing, 1972.

CHARLES RIVER ASSOCIATES. *The Effect of Automotive Fuel Conservation Measures on Automotive Air Pollution*. Cambridge, Mass.: 1975.

DATA RESOURCES INC. *A Study of the Quarterly Demand for Gasoline and Impacts of Alternative Taxes*. Lexington, Mass.: 1973.

GRELLE, D. "State Differences in the Demand for Gasoline." *Energy and Policy*, Vol. 3, No. 2 (1979).

HARBERGER, A.C., ED. *The Demand for Durable Goods*. Chicago: University of Chicago Press, 1960.

HAUSMAN, J. "Specification Tests in Econometrics." *Econometrica*, Vol. 46 (November 1978).

HECKMAN, J. "Dummy Endogenous Variables in a Simultaneous Equation System." *Econometrica*, Vol. 46 (July 1978).

HOUTHAKKER, H. AND KENNEDY, M. "The World Demand for Petroleum." Lexington, Mass.: Data Resources Inc., 1974.

KRAVIS, I.B. *International Comparisons of Real Product and Purchasing Power*. Washington, D.C.: IBRD, 1978.

LEE, L.F. AND TROST, R. "Estimation of Some Limited Dependent Variable Models with Application to Housing." *Journal of Econometrics*, Vol. 8 (1978).

MCFADDEN, D., ED. *Structural Analysis of Discrete Data*. Cambridge: MIT Press, 1982.

MOTOR VEHICLE MANUFACTURERS ASSOCIATION. *World Motor Vehicle Data*. 1970, 1972.

OI, W. AND SHULDINER, P. *An Analysis of Urban Travel Demands*. Evanston, Ill.: Northwestern, 1962.

OWEN, W. *Automobiles and Cities: Strategies for Developing Cities*. Washington, D.C.: IBRD, 1973.

PINDYCK, R. *The Structure of World Energy Demand*. Cambridge: MIT Press, 1979.

S.M.M. & T.L.T.D. "Schedule of World Import Duties for Cars, Commercial Vehicles and Parts." London: 1972, 1976.

SWEENEY, J. L. "Energy Policy and Automobile Use of Gasoline." Stanford University, 1978.

U.S. BUREAU OF MINES. *International Petroleum Statistics*. Washington, D.C.: 1970, 1972.

U.S. ENVIRONMENTAL PROTECTION AGENCY. *Gas Mileage Guide for New Car Buyers*. Washington, D.C.: 1974–1978.

WILDHORN, S. *et al. How to Save Gasoline*. Santa Monica: Rand Corporation, 1974.

182

11

Appendix to 90-010

VALUATION OF ENVIRONMENTAL EXTERNALITIES FOR ENERGY PLANNING AND OPERATIONS

MAY 1990 UPDATE

Stephen S. Bernow
Donald B. Marron

May 18, 1990

Tellus Institute
89 Broad Street
Boston, Massachusetts 02110

Telephone: (617) 426-5844
Telefax: (617) 426-7692

183

Table of Contents

1. INTRODUCTION 1

2. CONTEXT 2

3. VALUATION METHODS 3

4. VALUATION RESULTS 7
   - Oxides of Nitrogen (NO_x) 10
   - Oxides of Sulfur (SO_x) 15
   - Volatile Organic Compounds (VOCs and ROGs) 17
   - Particulates (TSP and PM_{10}) 21
   - Carbon Monoxide (CO) 23
   - Carbon Dioxide (CO_2) 26
   - Other Greenhouse Gases (CH_4, N_2O, CO, NO_x) 28
   - Summary of Cost Estimates 33

5. USE OF THE ENVIRONMENTAL COST ESTIMATES 34

ACKNOWLEDGEMENTS 38

SOURCES 39

184

1. INTRODUCTION

Increasing attention has been given of late to the problem of incorporating environmental issues in energy resource planning. A variety of methods for achieving such incorporation have been suggested, including the use of monetized environmental costs, weighting and ranking schemes, fixed percentage adders for non-combustion technologies, and other approaches. In this report, we discuss the monetization of environmental costs, which we believe to be a particularly useful approach for including environmental issues in energy resource planning.

We have two basic reasons for this belief (they are set out in much greater detail in Shimshak et al. (1990b)). First, the use of monetized values allows for clear and understandable comparisons to be made between direct economic costs (e.g, fuel costs) and environmental costs. If these costs of energy planning are not expressed in common units, comparisons become confused and the tradeoffs between economics and environment may become less comprehensible. Second, and more important, monetization allows for the consistent treatment and evaluation of environmental issues in a manner that other methods do not. Once costs are developed for, for example, air emissions, those costs can be easily applied in many contexts within the energy sector, for example in planning, acquisition of resources, and operation of electric generating facilities, as well as in other sectors of the economy. Systems that do not use monetization cannot provide such flexibility, and thus will not allow for consistent treatment of externalities over a range of economic contexts. At the same time, monetization does allow, as do the other systems, for the use of judgmental policy weights in the application of costs. Thus, use of monetization need not be viewed as incompatible with the subjective/judgmental aspects of other environmental evaluation methods.

In this report, we will explore in greater detail a variety of methods that have been suggested, and used, for developing monetized cost estimates for environmental externalities. The direct costing of damages is clearly the preferred approach, *when appropriate and feasible*. Among other costing methods we discuss are those based on control costs and regulatory requirements and those based on willingness to pay additional resource costs to avoid the risk of environmental damages. Using one specific costing method, the "revealed preferences" approach, we then develop cost estimates for a range of air emissions. We conclude with a brief discussion of how these costs may be used in the energy planning process to improve the overall *societal* efficiency of resource use.

185

2. CONTEXT

Energy resources impose a variety of costs on society. Some costs, e.g., the direct costs of power plant construction, operation, and fuel consumption, are borne directly by the utility and, in turn, by the consumer. Other costs, however, are not directly borne by the utility or consumer. Most notable among these *external* costs are the damages to human health and the environment that result from the construction of energy facilities, the extraction, processing, and combustion of fossil fuels, and the mining, processing, and disposal of nuclear fuels.

Economists have argued that inefficient (i.e. suboptimal) economic outcomes result when external costs are not incorporated in economic decisions.[1] Within the electric sector, for example, consumers are not charged for the external damages that their electricity demand causes, and thus they tend to demand "too much" electricity. Similarly, utilities do not incorporate external costs in their economic calculus, and thus may tend to pursue the "wrong" types of electric resource options. Similar externalities (and resultant inefficiencies) occur throughout the energy sector in the consumption of natural gas and other fuels.

In order to improve utility resource decisions (and, ultimately, consumer purchasing decisions), economists have argued that external costs should be "internalized" to the utility decision-making process and, ultimately, passed on to energy consumers. In this way, the correct price signals would be created, leading to the satisfaction of energy needs at the lowest overall cost to society. Many analysts (including the authors) have argued that one reasonable method for achieving such internalization is to require that explicit monetary estimates of external costs be included in utility decision-making (see, e.g., Tellus Institute 1990a,b,c; Shimshak et al. 1990a,b,c; and Chernick and Caverhill 1989, 1990). Regulators in a number of jurisdictions have already adopted (e.g., New York and California) or are considering (e.g., Massachusetts) such approaches.

---

[1] *This is true both within relatively narrow economic perspectives that measure economic performance only in terms of productivity, income, GDP, etc. and within broader economic perspectives that account for concepts of welfare that fall outside traditional economic measures.*

186

3. VALUATION METHODS

The art and science of attributing costs to the environmental impacts of energy production and use are still in their developing stages. At this time, two general approaches have been taken to the problem, one emphasizing the costs associated with environmental damage and/or its remediation, the other emphasizing the costs of prevention.[2]

While some significant efforts have been made using the damage costing approach (see, e.g., Hall et al. 1989, Hohmeyer 1988, ECO Northwest et al. 1984, 1986, 1987, Pace University 1990), we are not convinced that they currently provide a suitable basis for valuing air emissions. We would like to note, however, that studies along the lines of Hall et al. (1989) could be of great relevance. That study estimated the economic benefits of improvements to human health that would result from improvements to air quality in the South Coast Air Basin of California (essentially the Los Angeles area). In our opinion, the study is an impressive effort at illustrating the economic value of improvements to air quality. Unfortunately, from the perspective of energy planning, the study was not designed to allow for the calculation of health benefits (or associated dollars) per unit of air emission (e.g., per ton of NO_x). For that reason, it is difficult to use the study results to generate air emissions values for use in energy planning. The study results are also only suitable for setting a lower bound on environmental/health benefits, since the study did not include all human health impacts, nor did it value such effects as visibility, materials damage, crop damage, etc. Finally, since the study focused only on the Los Angeles area, it would be difficult to transfer the results to the air quality situation in other parts of the country.

In general, damage costing approaches face two sets of problems. First, estimating the direct *physical* impacts of environmental insults (air emissions, water emissions, etc.) can be a large and exceedingly complex task, fraught with uncertainty. These impacts depend on the *emissions* loadings themselves, the *transport* of pollutants through various media, the *exposure* of receptor populations, and the *dose/response* relationship of those populations. Moreover, there can be a series of subsequent non-physical (e.g., socio-economic) as well as physical impacts that ensue in both the near and long term. The local, regional, and global consequences of air emissions, for example, depend upon atmospheric, biological, chemical, geophysical, ecological, and physiological relationships across time, space, and socio-economic and cultural conditions. In modelling such relationships, elements of scientific uncertainty,

---

[2] *Other methods could also be used. For example, one could develop relative weights for environmental issues based on polling of experts or consumers, and then multiply these weights by an overall environmental cost to determine the value placed on particular issues. NEES (1990) has proposed this type of polling system for valuing environmental externalities in New England.*

181

availability of accurate data, the ecological response to perturbation, including non-linearities and feedback effects, among other factors, must be taken into account. The net result is that the prediction of the direct impacts of environmental perturbations may be very difficult.

Second, the *valuation* of environmental damages can be both difficult and controversial. For economic goods that are traded in a market, estimation of environmental damages presents significant analytic challenges; valuation of non-market goods, moreover, provides even greater difficulties. Even if physical impacts can be estimated (in terms of premature human deaths, increases in respiratory problems, loss of species, etc.), significant uncertainties and questions arise when we attempt to place a dollar value on such impacts. While a variety of methods have been used for valuing non-market goods (including the methods of contingent valuation, hedonic pricing, willingness-to-pay, willingness-to-accept, etc., see OECD 1989), significant uncertainties remain. Moreover, it may be impossible *in principle* to directly establish costs for some of the consequences of environmental degradation: loss of habitat, loss of species, socio-cultural disruption, etc.

Given the significant difficulties that arise in attempts to value directly environmental externalities, many analysts have chosen to use control or prevention costs as surrogates for damage costs. As one example, in its 1990 Electricity Report planning exercise, the California Energy Commission recently adopted costs for certain air emissions that reflect the *average* cost of certain emissions control strategies that may be required under proposed air quality regulations for the South Coast Air Quality Management District (CEC 1990). Similarly, New York State recently developed costs based on *average* control costs to use in developing utility bidding systems (NY SEO et al. 1989a,b; Putta 1989).

While such cost estimates are relatively easy to implement in practice, the rationale for using average costs is not compelling. In general, there is no reason to believe that the costs of preventing a specific externality bear any simple relation to the actual damage costs for which they are used as proxies. Particularly noxious pollutants might be inexpensive to avoid, while relatively benign pollutants might be very expensive.

Because of this problem with simple cost of control valuation, a more nuanced control cost approach has been proposed, based on the notion of regulators' "revealed preferences" (Schilberg et al. 1989) or "shadow pricing" (Chernick and Caverhill 1989). In this approach, existing and proposed environmental regulations are analyzed in order to estimate the value that society implicitly places on specific environmental impacts. For example, acid rain legislation may be analyzed in order to estimate the costs society is willing to impose on itself to reduce emissions of SO_x. In analyzing the regulations, we can identify the highest (or marginal) cost reduction strategy required

by the regulations. This can then be taken as an estimate of the value that regulators (and society) have placed on air emissions. As the very least, it can be argued that this value represents the "revealed preferences" of regulators, and that, to be consistent, it ought to be applied when decisions affecting these environmental impacts are made.

The relationship between the two concepts of shadow prices and revealed preferences has a technical expression in certain analytical procedures that find optimal solutions to problems under constraints. For example, if a least cost energy plan subject to a CO_2 constraint is constructed using linear programming techniques, the shadow price is the implied value (benefit) of the last step in reaching that target (the marginal cost of pollution reduction). Choosing a target, however, itself requires or implies some perception or estimation of damages (if not damage costs), either as an external norm or as the benefit to which reduction costs are compared. In general one would compare the shadow prices for a series of targets and select that point at which the marginal cost and benefit are equal. Since damages may not always be expressible in cost terms directly, the choice of that point reflects a willingness to pay (i.e., incur additional costs to avoid the risk). By exploring such relationships one could reveal the implied preferences of regulators who have set such targets. In turn, such explicit exploration could serve to inform future policy discourse so that new preferences become revealed.

If one is willing to accept the notion of regulator rationality, moreover, then an argument can be made that the marginal control costs actually represent the cost to society of air emissions, since regulators, in their rationality, would have set their regulation so that marginal costs approximate marginal benefits. In practice, of course, the revealed preferences cost may be either higher or lower than actual damage costs, either through lack of information and insufficient analysis, or because a risk-averse or risk-taking margin is adopted.

The revealed preferences approach thus does have a number of difficulties. In particular, it is based on the notion that regulators and legislators base their decisions on some implicit and reasonably accurate conception of marginal costs and benefits, rather than on other political and social concerns (including, for example, the total costs or the impact on certain groups).[3] Moreover, we know that society's revealed preferences can change over time, as information, analysis, values, and policy change. Thus, a limitation of this approach is that past or current revealed preferences of regulators may bear little relation to the actual impacts and their value to society, that may be identified by further research and public debate. As examples, one could take

[3] *We should note that in recent comments before the Massachusetts Department of Public Utilities, state air quality regulators themselves questioned the assumptions about the process of regulation that underlie the revealed preference approach to monetization (MA DEQE 1990).*

129

the value placed by U.S. society on acid precipitation twenty years ago or on greenhouse warming today.

Despite these problems, we believe that the revealed preferences approach is still a useful way to estimate the values that society currently places on air emissions, in *lieu* of further research on actual damages/impacts and their costs. While that research is being pursued, as it should be, the use of emissions valuation figures based on regulator's revealed preferences can put into place (and into resource decisions that are soon to be made) a protocol that can provide a large additional benefit to conservation and non or low polluting supply options. For these reasons, we have primarily relied upon the revealed preferences approach in developing the cost estimates presented in the following sections.[4]

---

[4] *We have previously recommended the use of the revealed preferences method in comments before the Massachusetts Department of Public Utilities (Shimshak et al. 1990b,c), in a report to the California Public Utilities Commission (Tellus Institute 1990b), and in a report to a group of Rhode Island Agencies (Tellus Institute 1990c). We have also developed and applied a slightly different approach -- the environmental target approach -- in a study prepared for the Vermont Department of Public Service (Tellus Institute 1990a). This approach, and its relationship to revealed preferences, is described briefly in the final section of this report.*

90

4. VALUATION RESULTS

It would be appropriate, in principle, to include all the external costs of energy resources (e.g., damages to the environment, damages to human health, cost of government subsidies, etc.) within an energy planning analysis. Given practical limitations, however, it has not be possible, as yet, to develop reasonable cost estimates for all such externalities (water pollution, noise, traffic, etc.). For that reason, we have thus far focused our research on air emissions. At this time, we have developed cost estimates for eight specific air pollutants:

Oxides of Nitrogen	NO_x
Oxides of Sulfur	SO_x
Particulates	TSP/PM_{10}
Volatile Organic Compounds	VOC/ROG
Carbon Monoxide	CO
Carbon Dioxide	CO_2
Methane	CH_4
Nitrous Oxide	N_2O

The first five air pollutants are currently regulated under federal standards because of their impacts on human health and welfare. They are also regulated under certain state air quality standards. The last three pollutants, not yet specifically regulated, are the principal "greenhouse gases" which, through increased concentrations in the atmosphere, can contribute to greenhouse warming and associated climate change on global and regional scales. (NO_x and CO can also contribute to greenhouse warming.)

Because specific regulations have been promulgated regarding emissions rates and ambient concentrations of the first five air pollutants, we have been able to use the revealed preferences method to develop estimates of the costs that regulators have placed on these emissions. Since no regulations currently exist for the greenhouse gases, as such, we have not been able to rely upon that approach in developing cost estimates for them. As is described in much greater detail in the CO_2 and other greenhouse gases sections below, our cost estimates for these emissions depend upon an estimate of what level of regulation might result from the current concern about emissions of greenhouse gases and their potential consequences.

As a prelude to our discussion of cost estimates for these air emissions, it is necessary to introduce some of the air emissions regulations that will be referenced in the following sections.[5] Under the Clean Air Act of 1970, as amended, the United

[5] *This discussion follows closely that given in Appendix A of U.S. DOE (1988).*

State Environmental Protection Agency (EPA) was given the authority and responsibility for developing National Ambient Air Quality Standards (NAAQS) that establish permissible ambient concentrations of air pollutants. Six "criteria" pollutants are currently so regulated: NO_x, SO_x, particulates, CO, ozone, and lead. Regulatory limits for VOCs were also established, but only as a reference in regard to the ozone standard. These federal standards were set primarily to protect the public health, with a secondary goal of protecting the public welfare (e.g., by limiting pollutant damages to buildings, materials, crops, forests, etc.). Each air quality control region, or portion of a region, is designated as attaining, not attaining, or incapable of being classified for each NAAQS standard (in practice, unclassified areas are treated as though they are in attainment).

The EPA has delegated its enforcement responsibilities to state air quality agencies which, in turn, oversee the activities of local air quality districts. The states are required to submit to the EPA a state implementation plan (SIP) that provides for meeting, maintaining, and enforcing the NAAQS standards within each air quality district.

In each geographic area, the attainment designation for each pollutant (attainment, non-attainment) is used to determine what pollution control standards are to be applied to new sources. In non-attainment areas, new sources are required to meet a Least Achievable Emissions Rate (LAER) criterion. In essence, the LAER requires that pollution control devices be installed on new facilities if they are technically feasible, regardless of cost. In attainment areas (or unclassified areas), the Prevention of Significant Deterioration (PSD) regulations require that new sources satisfy a Best Available Control Technology (BACT) standard. In addition to technical feasibility, BACT analyses also consider the economics of potential pollution control devices. In addition to the LAER and BACT standards, facilities must also satisfy the New Source Performance Standards (NSPS), which specify maximal emissions rates for various pollutants.

As of this writing, Congress and the Administration are attempting to enact a significantly revised Clean Air Act; changes to the Act may have substantial implications for the costing results we present below. Also note that, in certain cases (e.g., California), states may have enacted air quality regulations that are more stringent and/or affect more pollutants than do the NAAQS standards.

As is well known, Southern California, in particular the South Coast Air Quality Management District (SCAQMD), has, in general, the worst air quality in the nation. For that reason, SCAQMD regulators have developed and analyzed a broad array of air quality regulations. The SCAQMD regulations, and their related analyses, provide a wealth of data regarding the costs of meeting existing air quality standards. These regulations, along with the federal standards described above, will serve as the basis

192

for our revealed preferences analysis in the following sections. As noted earlier, in this approach, revealed preferences, as they are related to perceived risk and policy at the local as well as national levels, can differ in magnitude from one place to another.

Given this brief primer on air quality regulations, we now present our estimates of air emissions costs. All of our cost estimates will be presented in constant 1989 dollars.

Oxides of Nitrogen (NO_x)

Introduction: NO_x emissions contribute to many air quality problems. Because of their direct effects on human health and welfare, emissions of NO_x are specifically regulated under the federal NAAQS. In addition, NO_x emissions contribute to the formation of particulates and ozone, two other criteria pollutants regulated under the NAAQS. On a more regional level, NO_x is, along with SO_x, an important precursor of acid rain. On a global level, finally, NO_x emissions also contribute to global warming (see the discussion under "Other Greenhouse Gases" below).

Our Cost Estimates: In the Northeast, there is a growing consensus that BACT for NO_x emissions from new natural gas turbines is 9 ppmv (at 15 percent O_2, dry basis).[6] As a rough rule of thumb, 9 ppmv corresponds to a NO_x emissions factor of about 0.036 pounds per MMBtu of fuel input (McVay 1990).[7] To meet this standard, facilities must generally install two types of NO_x control devices: steam or water injection (SWI) *and* selective catalytic reduction (SCR). The injection of steam or water in the combustion chamber lowers combustion temperatures and thus reduces the creation of thermal NO_x, the principal source of NO_x when fuels are burned that contain little nitrogen. In contrast, SCR is an exhaust gas treatment technology that is installed downstream from combustion. Ammonia (NH_3) is injected into the exhaust gas and then reacts with the NO_x in the presence of a catalyst.

Taken alone, either SWI or SCR can be used to achieve about an 80% reduction in NO_x emissions (i.e., they can reduce emissions from about 125 ppmv to about 25 ppmv) (Sidebotham and Williams 1990). To achieve 9 ppmv, however, both SWI and SCR are required. Given the 9 ppmv standard, and given that SCR is more expensive than SWI, it would thus appear that the "marginal" NO_x control technology required to comply with the standards is SCR, and that to estimate marginal costs it will be sufficient to estimate the costs of SCR installation and operation. Unfortunately, this is not quite correct. Once the SCR is added to the system, SWI is needed only to reduce NO_x to about 42 ppmv so that together they reach 9 ppmv. While SWI alone can be used to lower emissions to as low as 25 ppmv, significant costs are incurred in going from the 42 ppmv level to 25 ppmv. These costs include significant increases in emissions of CO and VOCs, as well as substantial reductions in

---

[6] *For example, the directors of the Northeast States for Coordinated Air Use Management (NESCAUM) have recommended this value. In one of the first applications of this policy, the Rhode Island Department of Environmental Management (RIDEM) has required that natural gas projects in the state (e.g., the proposed repowering by Narragansett Electric of its Manchester Street Station) satisfy this limit.*

[7] *The conversion between ppmv and lbs/MMBtu depends on a variety of engineering parameters, and thus analysts' estimates of this conversion vary significantly. The CEC (1990), for example, has estimated that 9 ppmv is equivalent to only 0.0275 lbs/MMBtu, while an ADL study (Benson et al. 1988) used a figure on the order of 0.039 lbs/MMBtu. Based on our review of the literature, we believe the higher end of this range is more representative.*

194

the lifetimes of the combustion chamber and turbines (McVay 1990, ENSR 1990, Benson 1990). Thus, the addition of the SCR results in both costs and benefits that need to be evaluated in order to determine the *net* marginal cost of SCR.

Unfortunately, we do not currently have sufficient information to carry out this detailed calculation. For that reason, we have adopted a simpler estimation approach, treating SCR as the marginal technology that is used to reduce NO_x emissions from a 42 ppmv level, attained with SWI alone, to the desired 9 ppmv level. In this calculation, we have estimated SCR costs and divided them by this reduction in emissions in order to determine the marginal cost per pound of NO_x reduction.

We have developed both our cost and emissions reductions estimates from a recent study of SCR costs by Benson et al. (1988). In this study, Benson et al. have estimated the costs of SCR used to reduce emissions from 42 ppmv to 9 ppmv on a range of reciprocating and gas turbine engines. As shown in Table 1 (which appears at the end of this section), we have adapted their cost and emissions estimates to determine that, for the range of engines they analyzed, SCR costs from $2,750 to $8,900 per ton ($1.37 to $4.45 per pound), in 1989 dollars. Given the rationale for the marginal costing approach we have adopted, it would seem appropriate to select the highest cost as our "revealed preferences" cost estimate for NO_x. However, we are not certain that SCR would be required on turbines as small as 3.5 MW, and thus we have adopted a value of $3.25 per pound of NO_x, based on the value given for the 10 MW facility. This **$3.25 per pound** figure is likely a reasonable cost estimate anywhere natural gas turbines need to satisfy a BACT standard of 9 ppmv.

In **southern California**, control regulations have been promulgated for a broad range of NO_x emissions sources. In developing its *1989 Air Quality Management Plan* (SCAQMD and SCAG 1989), the SCAQMD estimated the costs associated with the various regulations it has proposed (SCAQMD 1989). It found that for NO_x, the most expensive regulation (C-5, calling for NO_x controls on afterburners, a VOC control technology) would cost up to $173,800 per ton, in 1987 present value dollars.[8] The California Energy Commission's (CEC) 1990 Electricity Report Commission has estimated that a different SCAQMD cost estimate for NO_x control, $11,600 per ton in 1987 present value, was equivalent to $16,281 per ton in 1987 constant dollars (CEC 1990). We thus estimate that the afterburner cost is equivalent to about $244,000 per

[8] *Unfortunately, the SCAQMD was not able to develop cost estimates for all of its proposed regulations. Thus, some NO_x control regulations may have even higher costs. This caveat applies equally to all the other emissions analyzed by the SCAQMD.*

145

ton in 1987 dollars (= $173,800 * 16,281/11,600), or $262,000 per ton or **$131 per pound** in 1989, assuming inflation at the rate of the GNP deflator.[9]

Regulators have thus been willing to require NO_x control technologies with costs at least as high as the following (in 1989 dollars):

Northeast U.S.	**$6,500 per ton**	**$3.25 per pound**
Southern California	**$262,000 per ton**	**$131 per pound**

Note that these cost estimates reflect *existing* air quality legislation and regulation. They do not include any global warming costs that may be associated with NO_x. Chernick and Caverhill (1990) have argued that these costs are independent, and thus should be added to the acid rain/ambient air quality costs. We address this issue in the later section on non-CO_2 greenhouse gases.

Other Cost Estimates: In order to place our cost estimates in context, it is useful to consider cost estimates that have been made by other parties. Chernick and Caverhill (1990), relying on the same Benson et al. (1988) study we have used, have derived a higher value of $4.00 per pound of NO_x for use in Massachusetts. In deriving this figure, they essentially adopted the cost figures given in that study (they adjusted the fixed charge rate and lowered some operating costs), but divided it by a significantly lower estimate of emissions reductions. They rejected Benson et al.'s emissions reductions estimates because they (mistakenly) believed that Benson et al. had attributed some emissions reductions from SWI to the SCR. Given this misinterpretation, Chernick and Caverhill then developed a lower estimate of emissions reductions based on emissions coefficients that correspond to roughly a reduction from 25 ppmv to 9 ppmv.[10]

In developing recommendations for New York State's electric resource bidding process, the New York Department of Public Service estimated values of roughly $1,800 per ton of NO_x, based on a 80/20 mix of low NO_x burners (at $400 per ton) and SCR (at $7,000 per ton) (Putta 1989 and New York State Energy Office et al. 1989a,b). These costs are in levelized nominal dollars; in constant 1989 dollars, these

---

[9] *According to the 1990 Economic Report of the President (Council of Economic Advisors 1990), the GNP deflator index was 126.3 in 1989 and 117.4 in 1987.*

[10] *As noted earlier, the use of SWI alone to reach 25 ppmv may be questionable, given potential engineering, environmental, and economic impacts. Thus, if SCR were added to SWI at a base of 25 ppmv to reach 9 ppmv (rather than an additional 80 % reduction to 6 ppmv, which is below the required level) these extra costs of SWI would have to be taken into account, assuming that with SCR, the SWI contribution is relaxed back to 42 ppmv. As a result of this, to use the Benson et al. (1988) numbers for SCR costs applied to a reduction from 25 to 9 ppmv, without making the foregoing adjustments, would likely give inappropriately high costs per ton of NO_x reduction at the margin.*

196

figures would be about a third lower. Thus, the 80/20 mix would cost about $1,200 per ton or $0.60 per pound.

As part of its 1990 Electricity Report proceeding, the California Energy Commission (CEC) Staff recommended a value of $11,600 per ton for in-state emissions, in 1987 present value, (Therkelsen 1989), or about $16,300 per ton in constant 1989 dollars (CEC 1990). This value was based on the *average* cost of certain control measures required under the SCAQMD's stringent air quality regulations. The CEC Staff also recommended that out-of-state emissions be assigned a value of one-tenth the southern California value. This large (and arbitrary difference) is intended to represent the difference in air quality between southern California and other states. After public hearings on these issues, the CEC ultimately adopted a NO_x value of $5,900 per ton (again in 1987 present value dollars) for emissions in southern California and a value of $0 for emissions elsewhere (CEC 1990). We estimate that this value works out to about $8,900 per ton or $4.45 per pound when converted to 1989 dollars using the CEC estimate and the GNP deflator.

As noted, both the New York DPS figures and the CEC estimates are based on some measure of *average* rather than marginal control costs required to meet regulatory standards. Thus, they are strictly speaking inappropriate for use in estimating the revealed preferences embodied in those regulations. On the other hand, they do appear to reflect the revealed preferences of the CEC and the New York DPS.

Issues for Further Research: The discussion above indicates a number of lines of further research that should be pursued in future attempts to refine our revealed preferences cost estimates for NO_x. To begin with, it may be appropriate to attempt the cost analysis that compares a 25 ppmv standard with a 9 ppmv standard. As noted above, this analysis will need to consider the impacts of 25 ppmv SWI on turbine lifetimes, as well as the value of increased emissions of CO and VOCs. As a more general issue, the impacts of NO_x controls on other emissions (e.g., CO, VOCs, ammonia, and particulates) should be included within any refined calculations. In particular, some effort should be made to evaluate the costs associated with ammonia (NH_3) emissions and storage.

Since, as noted, the value of NO_x emissions can vary with location, efforts should be made to develop estimates for other areas of the country. Also, revised Clean Air Act legislation is currently pending in the U.S. Congress. Our NO_x cost estimates may need to be revised once such legislation is finalized.

197

TABLE 1: COSTS FOR USING SCR TO CONTROL NO_x

Based on Benson et al. (1988), pp. 30-33.

	Gas Turbines				Reciprocating Engines	
0. Capacity: MW	3.5	10	35	75	3.5	10
HP	4,700	13,400	47,000	101,000	4,700	13,400
1. SCR Capital Cost	$430,000	$740,000	$1,950,000	$3,880,000	$430,000	$740,000
2. Amortized SCR Capital Cost	$43,000	$74,000	$195,000	$388,000	$43,000	$74,000
3. SCR Annual Operating Costs	$85,654	$193,840	$609,940	$1,275,700	$87,187	$198,220
4. Total SCR Annual Costs	$128,654	$267,840	$804,940	$1,663,700	$130,187	$272,220
5. Annual NOx Reduction (in tons)	15.0	42.9	150.4	323.2	36.2	103.2
6. Cost per ton of NOx	$8,554	$6,246	$5,352	$5,148	$3,597	$2,638
escalated to 1989 dollars:	$8,907	$6,504	$5,573	$5,360	$3,746	$2,747
7. Cost per pound of NOx	$4.28	$3.12	$2.68	$2.57	$1.80	$1.32
escalated to 1989 dollars:	$4.45	$3.25	$2.79	$2.68	$1.87	$1.37

INPUT DATA

Annual NOx Reduction: Gas Turbines — 3.2 tons per 1000 HP
Recip. Engines — 7.7 tons per 1000 HP

Annual Real Levelized Fixed Charge Rate: 10.00%
Average Capacity Factor: 50%
Inflation from 1988 to 1989: 4.12%

NOTES

a. The total capital cost and operating costs figures are taken directly from Benson et al. (1988).
b. The amortized capital costs are based on a 10% real levelized fixed charge rate. This is used (rather than a more typical nominal fixed charge rate) because we need costs to be expressed in real dollars.
c. The reduction estimates are also taken directly from Benson et al. (1988); they correspond to emissions reductions from 42 ppmv to 9 ppmv.
d. The cost figures in Benson et al. (1988) are expressed in 1988 dollars (Benson 1990).
e. Inflation is based on the GNP deflator (1990 Economic Report of the President).

198

Oxides of Sulfur (SO_x)

Introduction: SO_x emissions contribute to both local and regional air quality problems. On a local level, SO_x emissions are regulated under the federal NAAQS because of their direct effects on human health and welfare. On a more regional level, SO_x is the principal cause of acid rain.

Our Cost Estimates: In the utility sector, the two basic methods of controlling SO_x emissions are use of low sulfur fuel and installation of flue gas scrubbing systems. In general, use of scrubbing equipment appears to be the more expensive control option required under current regulatory standards. Based on a review of a number of scrubbing cost estimates (e.g., those in NY SEO et al. 1989a,b), we have estimated that scrubbing costs at least $1,500 per ton in 1989 dollars.

Pending acid rain legislation appears likely to include an emissions trading system for SO_x emissions. To enable new sources to have access to credits in the early years of such a program, one amendment has called for a fixed-price reserve of 100,000 tons of emissions credits to be available at $1,500 per ton (Electric Utility Week 1990).

Based on these two sources, we conclude that $1,500 per ton, or **$0.75 per pound**, is an appropriate cost estimate for SO_x emissions in the U.S.

Based on the SCAQMD regulations, we have developed a SO_x cost estimate for use in **southern California**. In order to meet federal and state standards for SO_x emissions, the SCAQMD proposed a broad range of SO_x control regulations as part of its *1989 Air Quality Management Plan* (SCAG and SCAQMD 1989). The SCAQMD estimated that the costs of the SO_x control measures would range up to $50,000 per ton, in 1987 present value, for control measure B-7, which applies to oil refinery cracking (SCAQMD 1989). Based on the conversion we did for the NO_x costs, we estimate that this figure is equal to about $75,000 per ton, or **$37.50 per pound**, in 1989 constant dollars.

Regulators have thus been willing to require SO_x control technologies with costs at least as high as the following (in 1989 dollars):

Entire U.S.	**$1,500 per ton**	**$0.75 per pound**
Southern California	$75,000 per ton	$37.50 per pound

Other Cost Estimates: Chernick and Caverhill (1989) have developed an estimate of $1,750 per ton or $0.88 per pound, based on a review of pending acid rain legislation

199

and the costs of fuel switching, for use in Massachusetts. This value is essentially the same as our estimate for the U.S. in general.

The New York Department of Public Service has recommended a value of about $800 per ton for SO_x. This figure is based on a 20-80 mix of switching to lower sulfur fuels (at a cost of about $200 per ton) and installation of scrubbers (at roughly $950 per ton) (Putta 1989 and New York State Energy Office et al. 1989a,b); in levelized 1989 dollars, these figures would be about a third lower. Thus, the 20/80 mix would cost about $533 per ton or $0.27 per pound.

The California Energy Commission (CEC) has adopted values of $11,500 per ton (in 1987 present value dollars) for southern California and $0 elsewhere (CEC 1990). The value for southern California was based on the average cost of certain controls recommended by the South Coast Air Quality Management District (SCAQMD). We estimate that this cost is equivalent to about $17,350 per ton or $8.68 per pound in 1989 dollars.

Areas for Further Research: As noted above, revised Clean Air Act legislation is currently pending in the U.S. Congress. Our SO_x cost estimates may need to be revised once there is final legislation on this matter. Also, the advent of an emissions trading system for SO_x emissions may provide a market in which the value of a ton of SO_x will be established. Since utilities and other polluters will need emissions credits in order to pollute, it may be that the costs of SO_x will be internalized at the market price of SO_x credits. The need for independent estimates of emissions costs for SO_x may then be obviated (except for those emitters that operate. for one reason or another, outside the trading/regulatory system).

In an entirely different vein, we should note that one of the principal methods of SO_x reduction, scrubbing, simply acts to transfer sulfur from one media (air) to another (scrubber wastes). Research effort should be focused on valuing these other products, so that polluters are not rewarded merely for moving a pollutant from one medium to another (this, of course, is a generic issue in environmental regulation).

Volatile Organic Compounds (VOCs and ROGs)

Introduction: In the presence of sunlight, volatile organic compounds (VOCs) and NO_x interact to form ozone, one of the six NAAQS criteria pollutants. At high concentrations, ground level ozone is considered dangerous to human health because of its effects on respiration. High ozone concentrations also damage crops, forests, and wildlife. VOCs themselves are regulated under the NAAQS, but only as a reference standard in regard to the ozone standard. So far, ozone has proven to be the most difficult of the criteria pollutants to control. At this time, about 100 urban areas still violate the federal standard, i.e., are non-attainment for ozone (OTA 1989). While the principal sources of VOC emissions are the transportation, industrial, and commercial sectors, power plants and end-use devices also contribute.

A clarifying note is in order, regarding the classification of VOCs. A variety of different chemical groupings have been used in describing the VOC class of pollutant. The class used in the NAAQS is actually nonmethane hydrocarbons (NMHC). Many analysts and regulators have focused on VOCs (as we do here) or on total hydrocarbons (THC or HC), while in California, regulators focus on reactive organic gases (ROGs). The difference between these similar groupings need not concern us here. For current purposes, we believe it appropriate to develop generic cost estimates for VOCs, as well as a southern California specific estimate for ROGs.

Our Cost Estimates: In order to develop national cost estimates for VOCs, we have examined a range of recent studies that have analyzed the costs of VOC control technologies that may be required to bring urban areas into attainment.[11]

In a pair of studies for the EPA, E. H. Pechan and Associates (Pechan) has estimated the costs associated with VOC control measures that would be required under various Clean Air bills pending in Congress (Pechan 1988, 1990). In the more recent of these studies, Pechan found that, for the three bills it analyzed[12], the costs would fall in the range of $130 to $2,000 per ton in 1995 for most identified control strategies. Improvements to architectural coatings were estimated to be costless ($0 per ton), while improvements to the tailpipe/useful life of vehicles had much higher costs (from $10,200 up to as much as $54,000 per ton). Pechan also estimated the costs of what it described as "assumed controls" that would also need to be implemented to meet federal standards. Pechan estimated that these unidentified

---

[11] *For another summary of these studies, see Denny Technical Services (1990).*

[12] *The study considered the original administration bill and the then-current House H.R. 3030 and Senate S.1630.*

201

controls would cost from $2,000 to $10,000 per ton, with an average of $5,000 per ton, again in 1995 dollars.[13]

In a parallel effort, the Congressional Office of Technology Assessment (OTA) has conducted a detailed study of methods to bring non-attainment areas into attainment with federal standards (OTA 1989). This study found that most control strategies in non-attainment areas would have a cost of $120 to $6,600 per ton in 1994. (In contrast to Pechan, the OTA found that improvements to architectural coatings would cost about $1,100 per ton). Use of methanol fuels, however, would cost significantly more, in the range of $8,700 to $51,000 per ton of VOC reduction.

The South Coast Air Quality Management District (SCAQMD) in **Southern California** has proposed a range of control measures that it believes are necessary to bring California's South Coast Air Basin (home of the nation's worst ozone problem) into attainment with federal and state air quality regulations (SCAQMD and SCAG 1989). As part of its analysis, the SCAQMD developed cost estimates for many proposed control measures for ROGs. They found that the required ROG control measures would have a cost ranging from net savings (e.g., for measure A-2, wood furniture coatings, and measure A-4, aerospace assembly coatings) up to $19,000 per ton (in 1987 present value) for measure A-5, automobile assembly coatings (SCAQMD 1989). In constant 1989 dollars, this higher value is equivalent to about $29,000 per ton or **$14.50 per pound.**

In developing VOC/ROG cost estimates, it must be kept in mind that ozone is primarily a local problem.[14] For that reason, we believe that it is appropriate to use different cost estimates in different areas. Since southern California has the worst air quality in the nation, in general, and ozone levels, in particular, we believe that, all else equal, it is appropriate to use apply higher costs to southern California than are applied elsewhere in the nation. As background for developing cost estimates, we note the following ozone "design values", in parts per million, for various areas (OTA 1989). The design values are a measure of the highest 1-hour average ozone concentration in an area; the federal ozone standard is 0.12 ppm for a 1-hour average:

---

[13] *As noted by Denny Technical Services (1990), a reasonable range for assumed controls might go even higher, e.g., to $20,000 per ton.*

[14] *This is not to say transport is unimportant; ozone from New York, for example, does appear in Boston (OTA 1989). In contrast to acid rain and global warming, however, ozone may be considered local.*

202

Area	1983-85	1985-87
Los Angeles-Long Beach, CA	0.36	0.35
Providence, RI	0.18	0.16
Boston, MA	0.16	0.14
New Bedford, MA	0.16	0.14

Based on the figures described above, we believe that a cost of at least $6,600 per ton of VOC (in 1994 dollars), is appropriate for areas, like Massachusetts and Rhode Island, that are **non-attainment** for ozone. This figure is the OTA's highest estimate, with the exception of the methane fuel costs, and is consistent with the mid-range of Pechan's "assumed control" costs. Assuming 4.5% inflation, our cost estimate is approximately $5,300 per ton of VOC in 1989 dollars, or **$2.65 per lb.** Given that Pechan's estimates for tailpipe/useful life improvements and "assumed controls" and OTA's estimates for methane fuels are substantially higher, we believe that this is a conservative cost estimate.

Given the extreme nature of the air quality problem in southern California, we believe that the $29,000 per ton of ROG figure, $14.50 per pound, derived from the SCAQMD regulations is appropriate. Thus, we recommend that the following values be used:

Non-attainment areas (VOC)	**$5,300 per ton**	**$2.65 per pound**
Southern California (ROG)	**$29,000 per ton**	**$14.50 per pound**

Other Cost Estimates: In examining the SCAQMD proposed regulations, the California Commission Staff recommended (Therkelsen 1989) and a CEC Committee approved (CEC 1990) a value of $3,300 per ton of ROG (in 1987 present value) for utility planning in the South Coast area. This figure, equivalent to about $5,000 per ton or $2.50 per pound in 1989 constant dollars, is based on the average cost of only two control measures (out of 28 for which costs were available).

Massachusetts has recently required the use of Stage II vapor recovery devices on gasoline stations. Based on cost estimates developed by the Massachusetts DEQE (MA DEQE 1989), Chernick and Caverhill (1990) have estimated that these devices cost about $2,000 per ton of VOC controlled (in 1989 dollars). As Chernick and Caverhill note, the American Petroleum Institute has estimated that the actual costs per ton will be at least double the MA DEQE estimates (API 1988). Chernick and Caverhill adopted the $2,000 per ton, $1.00 per pound, cost figure, however, since that was the cost regulators believed in requiring the vapor control devices.

We believe that both of these cost estimates are too low for their respective areas. As noted previously, the studies we reviewed indicated that significantly more

expensive control measures will be required in the SCAQMD, and in non-attainment areas generally, to meet ROG and VOC limits.

Issues for Further Research: As with many of our other cost estimates, it will be necessary to revisit these costs once revised Clean Air Act legislation is adopted. Also, it may be necessary to derive other estimates for areas that are in attainment and for those that have air quality worse than that in New England, but better than that in the SCAQMD area.

Particulates (TSP and PM_{10})

Introduction: Particulates are regulated under the federal NAAQS because of their impacts on human health (in particular on the respiratory system) and because of their impacts on visibility and other aspects of human welfare. Under the original NAAQS regulations (promulgated in 1971), all particulates, known as total suspended particulates or TSP, were regulated. In 1987, the TSP NAAQS standards were eliminated and replaced by standards for "thoracic" particulates. These are particulate matter with aerodynamic diameters less than 10 μm[15] (PM_{10}). TSP continue to be regulated under the NSPS and PSD standards, however. The EPA is currently considering the addition of secondary NAAQS particulate standards that would regulate "fine" particulates (particulates with aerodynamic diameters less than 2.5 μm).[16,17]

Our Cost Estimates: Chernick and Caverhill (1990) have estimated the incremental costs of satisfying the existing federal TSP standards in the U.S. by estimating the costs of using an electrostatic precipitator (ESP) to increase control from 95% to 99.9% on a high sulfur coal plant with low resistivity fly ash. Based on EPA figures (EPA 1984), they estimate a cost of $4,265 per ton or $2.13 per pound in 1989 dollars. They then round this to **$2.00 per pound.** We believe that this is a reasonable estimate for TSP costs. As Chernick and Caverhill note, however, actual marginal costs may be higher if ESP is applied to coal plants with lower emissions rates, to oil plants, or to coal plants that burn low sulfur coal with high resistivity fly ash.

While the TSP cost we have adopted is based on federal regulations, and thus is appropriate for use throughout the country, we have not yet developed a similar cost estimate for PM_{10} emissions. Based on the SCAQMD regulations, however, we have been able to develop a cost estimate for use in **southern California.** In order to meet federal and state standards for PM_{10} emissions, the SCAQMD proposed a broad range of PM_{10} control regulations as part of its *1989 Air Quality Management Plan* (SCAG and SCAQMD 1989). The SCAQMD estimated that the costs of the PM_{10} control measures would range up to $29,300 per ton, in 1987 present value, for control measure B-10, which applies to oil refinery cracking units (SCAQMD 1989). We have estimated that this is about $44,000 per ton, or **$22 per pound,** in 1989 dollars, based on the conversion methodology described previously for NO_x.

---

15 *A μm (or micron) is one millionth of a meter.*

16 *Thoracic particulates (PM_{10}) are often mistakenly referred to as "fine" particulates.*

17 *This discussion is based on Appendix A of U.S. DOE (1988).*

Regulators have thus been willing to require particulate control technologies with costs at least as high as the following (in 1989 dollars):

Entire U.S. (TSP)	**$4,000 per ton**	**$2.00 per pound**
South. California (PM_{10})	**$44,000 per ton**	**$22 per pound**

Other Cost Estimates: The New York Department of Public Service has recommended that a levelized value of $333 per ton be used in developing bidding systems in New York State (Putta 1989). We have estimated (Tellus Institute 1990a) that this value is equivalent to about $220 per ton or $0.11 per pound in constant 1989 dollars. The ÖKO-Institut in Darmstadt, Federal Republic of Germany has estimated that reduction of particulate emissions would cost about 1 DM/kg (Fritsche and Rausch 1989). Assuming a conversion rate of 1 DM = .54487 dollars, this works out to about $495 per ton or $0.25 per pound. The California Energy Commission, finally, has estimated the cost of reducing PM_{10} to be about $7,800 per ton, in 1987 present value, based on its averaging the costs of a range of SCAQMD control measures (Therkelsen 1989); this figure is roughly $11,700 per ton or $5.85 per pound in 1989 dollars.

Issues for Further Research: PM_{10} cost estimates should be developed for the rest of the U.S. To the extent that data are available, location-specific estimates would be appropriate, based on the location's PM_{10} air quality relative to the NAAQS standards. If the EPA adds secondary standards for fine particulates, costs should be developed for them as well. The simultaneous regulation of various types of particulates raises some questions regarding the use of costing estimates. While some further research may be necessary, we expect that it will be sufficient to disaggregate particulate emissions by size, and then cost them based on the highest cost developed for each size (e.g., PM_{10} in southern California may be valued at the PM_{10} cost, while non-PM_{10} particulates may be valued at the TSP cost).

206

Carbon Monoxide (CO)

Introduction: CO is regulated under the federal NAAQS because of its effects on human health, in particular respiration. As we discuss in a later section, CO, while not itself a greenhouse gas, can also contribute to the greenhouse effect.

Our Cost Estimates: In order to meet federal and state standards for CO emissions, the SCAQMD has proposed a number of CO control regulations as part of its *1989 Air Quality Management Plan* (SCAG and SCAQMD 1989). The SCAQMD estimated that the costs of the CO control measures in **southern California** would range up to $543 per ton, in 1987 present value, for control measure T-7, which requires an increase in the oxygenation of gasoline (SCAQMD 1989). As with the other estimates we have used from the SCAQMD, we have converted this figure to an estimate in 1989 dollars; in this case, the value is $820 per ton or **$0.41 per pound** in 1989 dollars.

At present, we have not specifically developed any values for use elsewhere in the U.S. However, we have prepared a rough estimate of the costs associated with using an oxidation catalyst (OC) for CO control on natural gas turbines. We have estimated the costs of an OC system based on a recent analysis by ENSR (1990) in Rhode Island. ENSR estimated the costs of applying OC to a turbine whose uncontrolled emissions rate is about 10 ppm, very low in comparison to other turbine types; because the emissions were already so low, they found that OC was not cost-effective in that application. A more typical uncontrolled emissions rate would be about 50 ppm, with controlled emissions of about 10 ppm (assuming 80% efficiency).[18] As shown in Table 2 (attached at the end of this section), using these emissions assumptions and the ENSR cost assumptions, we have estimated a CO cost of about $1,800 per ton or $0.90 per pound in 1989 dollars.

This result indicates that the $820 per ton value derived from the SCAQMD may be low compared to the costs of OC used to control CO in power plants. Since OC has already been found to be BACT in a number of cases, with emissions rate being controlled to about 10 ppm (ENSR 1990), we conclude that using the $820 per ton or **$0.41 per pound** value as a generic value in the **U.S.** is appropriate.

---

[18] *CO emissions vary greatly, depending on turbine configuration and on the amount of steam/water injection used to boost power or control NO_x. We have adopted the 50 ppm as a reasonable estimate for uncontrolled emissions based on the CEC (1989). In developing generic emissions coefficients for use in its 1990 Electricity Plan proceeding, the CEC assumed that uncontrolled emissions from a natural gas combined-cycle plant would be about 0.11 lbs per MMBtu of fuel input, or roughly 50 ppm, and that OC controlled emissions would be 80% lower, or roughly 10 ppm.*

Other Cost Estimates: Chernick and Caverhill (1990) have developed a value of $750 per ton ($0.375 per pound) based on the same SCAQMD document we cited above. The minor differences between our figures reflect different estimation procedures.

Although the SCAQMD did provide cost estimates for CO control, as noted, above, the California Energy Commission did not adopt any CO value for use in its 1990 Electricity Plan proceeding. In applying its averaging methodology, the CEC included none of the SCAQMD estimates, and thus it developed no value.

Areas for Further Research: Further research is necessary in order to determine the level of pollution control, and related expenses, that have been required outside the southern California area. While our calculation of OC costs is illustrative, more detailed analyses are needed for actual controls. In analyses of the costs of OC for CO control, the supplemental benefits of reduced VOC emissions should also be evaluated.

208

Table 2: COSTS FOR USING OXIDATION CATALYSTS TO CONTROL CO

Adapted from ENSR (1990), pp. 5-31 to 5-36

Total Installed Cost	$2,440,600
Real Fixed Charge Rate	10.00%

Cost Component	Annual Costs
Annualized Capital Costs	$244,060
Direct Operating Costs	
Labor	$24,300
Maintenance	$42,200
Replacement Parts	$390,500
Electric Power Loss	$318,900
Indirect Operating Costs	
Overhead	$39,900
Taxes	$24,400
Insurance	$24,400
Administration	$48,800
Total Annual Costs	$1,157,460
Annual Tons of CO Removed	645

CO Cost:	per ton	$1,795
	per pound	$0.90

Notes:

(1) Cost figures are taken directly from ENSR; our 10% fixed charge rate differs somewhat from their use of 9.8%

(2) Annual tons removed assume that the OC is used to reduce emissions from 50 ppm to 10 ppm (80% efficiency). The actual ENSR study analyzed the impact of reducing emissions from 10 ppm to 2 ppm. Thus, our cost per ton result is one fifth of theirs.

(3) The ENSR study concluded that OC was not BACT for the turbine they analyzed. However, they also noted that OC has been required to achieve 10 ppmv. In making the calculation shown here, we have assumed that the costs of OC control from 50 ppm to 10 ppm would be the same, per MW of installed capacity, as for the turbine analyzed by ENSR. Actual costs will likely differ. The costs results presented here should therefore only be treated as a rough estimate of the costs of using OC as BACT.

209

Carbon Dioxide (CO_2)

Introduction: CO_2 is the principal greenhouse gas, responsible for more than 50% (and perhaps as much as 70%) of global warming potential (Lashof and Ahuja 1990). At the moment, there are no U.S. emissions regulations regarding CO_2, and proposals for such regulations are only beginning to be specified. For that reason, it is not possible to apply directly the "revealed preferences" methodology to the estimation of CO_2 costs.[19] Instead, we have developed cost estimates based on a projection of what a moderate effort at CO_2 control would cost.

We should note, however, that other countries have begun to implement CO_2 control regulations. On February 1, 1990, for example, the Netherlands began to collect a CO_2 tax from users of fossil fuels. The Toronto City Council has resolved to cut CO_2 emissions by 20%, and the province of Ontario is considering whether to implement a 10 percent carbon release surcharge on fuel use. In 1988, moreover, a group of countries at a conference in Toronto informally agreed to reduce emissions 20% from 1985 levels by the year 2000. All these regulations/targets embody implicit acceptance of certain shadow prices. Of course, as higher levels of CO_2 reductions are sought, these revealed preferences will also increase.

Our Cost Estimates: Virtually all efforts to cost CO_2 based on control costs have assumed that trees could be planted as carbon sinks on otherwise unforested land. While estimates of tree planting costs display a great deal of variation, we have adopted the $22 per ton in 1989 dollars ($0.011 per pound) cost estimate developed by Chernick and Caverhill (1989). They derived their figure based on a review of tree planting costs and carbon uptake rates. Since CO_2 emissions are of global concern, this value applies in all areas of the country (indeed, in the world).

Other Cost Estimates: Tree planting cost estimates range from perhaps $3 per ton of CO_2 to well upwards of $20 per ton (Tellus Institute 1990 and Chernick and Caverhill 1989). As some examples within this range, the work of Sedjo and Solomon (1989) indicates costs in the $3 per ton range, the NRDC and Sierra Club have estimated a value of about $15 per ton (Calwell 1990), and the California Energy Commission has adopted a value of $7 per ton.

The New York Department of Public Service has recommended that a comparatively low value of about $1 per ton be used in New York's bidding system (Putta 1989; NY SEO et al. 1989a,b). This figure is 20% of the state's estimate that

---

[19] *Some might argue that there is an obvious revealed preference: $0. However, the tide of public opinion and policy development, not to mention the adoption of non-zero CO_2 costs by utility regulators in New York and California, indicate that the lack of regulation reflects regulatory lag, not the belief that CO_2 emissions are costless.*

210

tree planting costs are about $6 per ton (New York State Energy Office et al. 1989a,b). New York elected to include only 20% of the CO_2 control costs in its planning both because of the uncertainties surrounding the greenhouse effect and because of the state's unwillingness to unilaterally take upon itself the full costs of CO_2 abatement. While we believe that New York's concern with these matters has some merit, we have not adjusted our $22 per ton figure. In applications of this figure, however, we believe that it may be appropriate to consider "policy adjustment factors" of the type used by New York (for example, in a forthcoming report to a group of Rhode Island agencies [Tellus Institute 1990c], we have analyzed CO_2 costs of $22 per ton and $11 per ton, with the latter figure representing a policy option to devalue CO_2 by a factor of 2).

Other costs estimates for CO_2 have been developed based on the costs of CO_2 scrubbing devices (Steinberg, Cheng, and Horn 1984), other mechanical devices (Blok et al. 1989), and on the costs of altering energy systems to lower CO_2 emissions (Kram and Okken 1989), but we ignore those estimates here.

Issues for Further Research: As regulations regarding CO_2 emissions are developed, it will be necessary to estimate the costs implicit in them.

21

Other Greenhouse Gases (CH_4, N_2O, CO, NO_x)

Introduction: In addition to carbon dioxide, a number of other gases may contribute to greenhouse warming. These include methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), and oxides of nitrogen (NO_x), as well as the chloroflorocarbons (CFCs).[20] Cost estimates for these gases can be derived in two general ways. First, for some of the gases, it may be possible to identify specific control strategies that may be required if the gases are regulated as greenhouse gases. These control cost estimates could be used to value the emissions, just as tree planting costs were used to value CO_2. Second, insofar as these gases and CO_2 all contribute to a single environmental problem, the greenhouse effect, it is also reasonable to consider whether we could use CO_2 controls (i.e., tree planting) to offset emissions of the other greenhouse gases. In this approach, we would need to develop greenhouse warming equivalency factors which would tell us, for example, how much CO_2 we would need to sequester in trees in order to offset the effects of a given amount of CH_4 or N_2O emissions. For our current analysis, we have adopted this second approach.

Our Cost Estimates: A number of analysts have attempted to estimate how the global warming impact of one unit of a greenhouse gas (e.g., CH_4) compares to the impact of one unit of CO_2. Ramanathan et al. (1985), for example, have estimated how the relative instantaneous radiative forcing caused by a mole of various gases compares to the radiative forcing caused by a mole of CO_2. By adjusting for molecular weights, these estimates can be used to estimate how the relative instantaneous radiative forcing caused by a ton of various gases compares to the radiative forcing caused by a ton of CO_2.

For our purposes, however, we are not interested in the *instantaneous* radiative forcing caused by a ton of the various gases. Instead, we are interested in the *cumulative effect* caused by an emission of, e.g., one ton of each. To estimate this cumulative effect, it is necessary to integrate the instantaneous relative forcings over the lifetimes of the various gases. Since the gases have very different lifetimes (more precisely, decay rates) in the atmosphere, the resulting relative contributions to radiative forcing changes over time, and their relative contributions to the cumulative effects of greenhouse warming are very different from the instantaneous estimates. Simply put, all else equal, a shorter lived greenhouse gas will have a lower cumulative warming effect.

---

[20] *At this time, we have not yet attempted to generate cost estimates for the CFCs. We should note, however, that in April of this year, producers of CFCs began to be charged an excise tax of $1.37 per pound. The tax is slated to increase to $2.65 per pound in 1993 (Electrical World, April 1990).*

212

Lashof and Ahuja (1990) have developed global warming potential (GWP) estimates for a range of greenhouse gases in just this way. Relying on the instantaneous forcings developed by Ramanathan et al. (1985), they have integrated over time (1000 years) to capture the relative cumulative warming effects associated with the gases. They have estimated, for example, that a ton of CO will have 2.2 times the global warming impact of a ton of CO_2. CO thus has a GWP, by weight, of 2.2. They similarly found that CH_4 has a GWP, by weight, of 10, and that N_2O has a GWP, by weight, of 180.

Using these GWPs, we have estimated the costs of the greenhouse gases by multiplying these GWPs by our cost estimate for CO_2:

Greenhouse Gas	GWP	$/ton	$/pound
Carbon Dioxide	**1**	**$ 22**	**$0.011**
Carbon Monoxide	**2.2**	**$ 48**	**$0.024**
Methane	**10**	**$ 220**	**$0.11**
Nitrous Oxide	**180**	**$3,960**	**$1.98**

Note that the CO value should be added to the $820 per ton value ($0.41 per pound) that we derived for CO's ambient air quality effects. The costs should be added because the other cost estimates represents regulations that were not designed to deal with greenhouse warming. Now that greenhouse warming is recognized as a threat, it is appropriate to increase the CO cost estimate to reflect the additional costs that would be incurred to avoid greenhouse warming.

Other Cost Estimates: Use of different GWP estimates would, of course, result in different cost estimates for the non-CO_2 greenhouse gases. The Lashof and Ahuja (1990) GWPs used above represent the relative cumulative effects of radiative forcing caused by emissions of the greenhouse gases. As it happens, CO_2 has a substantially longer lifetime than do the other gases. Thus, while much of the radiative forcing caused by CH_4, for example, happens in the first two decades after emission, the forcing caused by CO_2 is spread over centuries. If policy-makers are more interested in radiative forcing that occurs in the next few decades, for example, rather than that which will happen in more than a century, they may desire to adjust the GWPs in order to account for the timing difference in impacts. As noted by Lashof and Ahuja (1990), one simple method for doing this is to discount radiative forcing, just as monetary values might be discounted in an economic analysis. The following table shows how the GWPs vary given varying discount rates:

	Discount Rates						
Greenhouse Gas	0%	1%	2%	3%	4%	5%	6%
Carbon Dioxide	1	1	1	1	1	1	1
Carbon Monoxide	2.2	4.0	5.0	5.5	5.7	5.9	5.9
Methane	10	34	48	58	65	71	76
Nitrous Oxide	180	345	345	337	330	324	319

These results indicate that the value placed on greenhouse emissions is very sensitive to the selection of a discount rate. In particular, the change from no discounting (0%) to discounting at just 1% per year roughly doubles the GWPs for CO and N_2O and more than triples the GWP for CH_4.

Many greenhouse analysts have argued compellingly that one of the principal concerns about global warming is the rapidity with which the climate changes, regionally as well as globally. Both the impacts of rapid changes, and the ability of ecosystems, biota, and socio-economic systems to respond (or adapt) to rapid changes or swings in climate, may be as problematic as the conditions under a warmer steady state itself. We agree that the rapidity of change may have comparable importance to overall climate change. Since the undiscounted Lashof and Ahuja GWPs are only concerned with cumulative radiative forcing impacts over time, they may not properly reflect concerns about the effects of rapid change.

Chernick and Caverhill (1990) have recently chosen to use the Lashof and Ahuja (1990) GWP results with a 6% discount rate. As part of their support for discounting, they have argued that the shorter-lived gases, in particular CH_4, contribute more to the speed of climate change, and thus it may be appropriate, for policy purposes, to give them higher GWPs. They therefore obtain substantially higher GWPs from the Lashof and Ahuja work than we have, and thus they generate higher estimates of the costs associated with the non-CO_2 greenhouse gases. However, we see no reason to believe that the use of discounting is the appropriate tool for adjusting the GWPs to reflect concerns about the rapidity of climate change. Discounting does have the effect of increasing the GWPs of the shorter-lived gases, but that effect is not directly related to the issue of rapidity of change.

Rotmans and den Elzen (1990) have developed GWP estimates (they call them Temperature Increasing Potentials or TIPs) using an approach different from that of Lashof and Ahuja (1990). Whereas Lashof and Ahuja relied upon a relatively simple analytic approach to the estimation problem, Rotmans and den Elzen have used an integrated greenhouse model, IMAGE, to estimate directly the global warming impacts caused by equal tonnage emissions of the greenhouse gases. Their results (assuming a time horizon of 100 years) are compared to the Lashof and Ahuja results in the following table:

214

Greenhouse Gas	Rotmans/ den Elzen	Lashof/ Ahuja
Carbon Dioxide	**1**	**1**
Carbon Monoxide	**NA**	**2.2**
Methane	**5**	**10**
Nitrous Oxide	**149**	**180**

Rotmans and den Elzen's estimates are lower than those of Lashof and Ahuja. For CH_4, part of this difference is explained by the fact that Lashof and Ahuja (1990) assumed a 70% enhancement of its radiative forcing due to its effects on tropospheric ozone and water vapor, while Rotmans and den Elzen (1990) did not. Adjusting for this factor, Rotmans and den Elzen's GWP (TIP) for CH_4 would be 8.5.

Based on our review of the GWP literature at this time, we believe that our use of the undiscounted Lashof and Ahuja (1990) estimates is a reasonable, but conservative assumption (i.e., it leads us to adopt costs at the low end of reasonable ranges). The Rotmans and den Elzen (1990) estimates are somewhat lower than those of Lashof and Ahuja (1990), indicating that actual GWPs may be lower than those that we have used. On the other hand, and likely larger effects, concern about the rapidity of climate change or use of discounting for policy purposes would indicate the use of higher GWP estimates.

As a final point, we should note that NO_x can also contribute to the greenhouse effect, both by forming ozone and by causing the release of methane from soils. Based on Steudler et al. (1989), Chernick and Caverhill (1990) have estimated that each pound of NO_x deposited on temperate forest soils will reduce methane by 0.004 to 0.07 pounds. Given our estimate of $0.11 per pound of methane, this works out to less than 0.008 cents per pound of NO_x deposited (Chernick and Caverhill derive a higher value because of their use of discounted GWPs). Since only a fraction of NO_x emissions are actually deposited on soils, the actual cost per pound of emissions would be even smaller. Because we have no information regarding the fraction of NO_x emissions that have this effect; we have not (unlike Chernick and Caverhill) included it in our costing analysis. In any case, compared to the ambient air quality costs of NO_x, this effect is apparently vanishingly small.

Issues for Further Research: The issue of discounting GWPs requires further thought. We agree that policy-makers may want to focus on the near term, either because of the far greater uncertainties over the longer term and the perceived need for quick action, or because of the belief that rapidity of change is a particular danger. As noted above, however, we are not convinced that use of discounting is the correct way to account for the rapidity of change issue. Instead, we believe it may be more appropriate to develop GWPs that explicitly address the rapidity issue.

215

Further efforts should also be focused on identifying control/offset strategies that might be used for the specific gases, rather than for an equivalent amount of CO_2.

Summary of Cost Estimates

All Costs are in 1989 Constant Dollars

		Northeast U.S		Southern California	
		$/ton	$/lb	$/ton	$/lb
1.	Nitrogen Oxides (NO_x)				
	Ambient Air Quality	$6,500	$3.50	$262,000	$131
	Greenhouse	$ 0	$0.00	$ 0	$ 0
	Total	$6,500	$3.50	$262,000	$131
2.	Sulfur Oxides (SO_x)	$1,500	$0.75	$ 75,000	$37.50
3.	Volatile Organics Gases				
	VOCs	$5,300	$2.65		
	ROGs			$ 29,000	$14.50
4.	Particulates*				
	TSP	$4,000	$2.00	$ 4,000	$ 2.00
	PM_{10}			$ 44,000	$22.00
5.	Carbon Monoxide (CO)				
	Ambient Air Quality	$ 820	$0.41	$ 820	$ 0.41
	Greenhouse	$ 50	$0.02	$ 50	$ 0.02
	Total	$ 870	$0.43	$ 870	$ 0.43
6.	Carbon Dioxide (CO_2)	$ 22	$0.011	$ 22	$ 0.011
7.	Methane (CH_4)	$ 220	$0.11	$ 220	$ 0.11
8.	Nitrous Oxide (N_2O)	$3,960	$1.98	$ 3,960	$ 1.98

* In southern California, the PM_{10} cost should be applied to emissions of PM_{10}, while the TSP cost should only be applied to additional particulate emissions that are *not* PM_{10}.

27

5. USE OF THE ENVIRONMENTAL COST ESTIMATES

Consistent with our belief that economic decision-making would be improved by the internalization of external costs, we recommend that the emissions costs we have just estimated be used within energy planning and operating decisions. In this section, we briefly describe some of the contexts in which these emissions costs may be useful.

Bidding Systems

Electric utilities are increasingly seeking new generating capacity (and, in some cases, demand-side management resources) through competitive bidding systems. Until now, evaluation of bids has primarily focused on the bid prices of the projects, with some adjustments made for likely viability, dispatchability, and similar characteristics. As we have argued in Massachusetts (Shimshak et al. 1990a,b,c), it is relatively straightforward to include costs for environmental externalities within such utility bidding systems. Bid projects will be required to specify their environmental characteristics (e.g., lbs of NO_x per MWH), upon which they will then be imputed environmental costs. These costs can then be used in a protocol for comparing and ranking the projects (again subject to concerns about viability etc.). For example, they may be added to the direct monetary costs (bid prices) of a proposal, in order to determine that proposal's overall *societal cost*. Note that use of the bidding system encourages proposed projects to pursue all pollution control that is less expensive than the imputed environmental costs. To ensure that projects do not provide misleading environmental data about themselves, contract terms can be specified that allow for adjustment to contracts if projects perform less well than originally claimed.

It is important to note in this context that, even with relatively high environmental adders, competing fossil fuel units will still produce substantial emissions. It is therefore very important that the bidding process be set up to encourage and ensure that a vigorous market of competing proposals is developed. This would help to ensure that the lowest overall cost options will be elicited and that non or low polluting supply resources will be drawn into the process. It is important, moreover, that energy conservation and, more generally, demand-side management be permitted to compete within an all resources process, in order that their relative pollution merits are adequately reflected in resource acquisition decisions.

Evaluation of Utility Resources

By the same token, environmental costs can also be imputed to resources within traditional resource selection procedures. Thus, if a utility is considering

218

resource additions outside of a bidding system, state regulatory agencies can require that it include environmental costs within its internal economic decision-making. We have recommended and adopted this approach, for example, in a recent study of Narragansett Electric's proposed repowering of its Manchester Street station (Tellus Institute 1990c), and in a study of alternative gas and electric supply and demand options related to a proposal for new natural gas pipeline capacity in California (Tellus Institute 1990b).

More generally, monetized environmental costs could be imputed to their sources in system-wide least cost evaluations. Here, the interactive effects of supply and demand resource would need to be evaluated, along with any impacts on non-electric sources of costs and emissions (e.g., in fossil-fired end-uses that replace electric generation or in steam boilers that are displaced by cogenerating facilities).

Least-Cost Dispatching

Ultimately, it would be appropriate to include environmental costs not only within utility planning decisions, but also within utility operating decisions. In particular, it would be appropriate to add variable environmental costs to the variable economic costs that are used to determine the dispatch of electric generating facilities. The result would be least *full cost dispatching*, that would reduce overall pollution (or the aggregate costs of such pollution) at some increase in direct costs. Such an approach would best be taken at the power pool level, at which conventional economic dispatch is performed. In this context, of course, the allocation among utilities of the additional costs resulting from the altered dispatch will be of particular concern.

Collecting External Costs

As discussed above, we believe that the external costs associated with environmental impacts should be imputed to their sources when evaluating utility planning (including bidding) and operations. In the electricity sector, in particular, this could involve adding the external costs of electricity production to direct costs in a systematic way.

One question that arises in this context is whether external costs should be merely *imputed* in the planning process, without actual collection from ratepayers ("phantom" costs), or whether they should actually be *collected* ("real" costs). Consistent with the traditional notion of economic efficiency, we believe that it may be appropriate to collect external costs from energy consumers. Consumers would then

219

be presented with "correct" price signals, rather than the artificially low prices that result from only imputing external costs to planning decisions.

By collecting actual externalities costs, the energy-related decisions of both electricity consumers (through increased conservation and fuel switching) and utilities (through changed priorities for dispatch and power purchases) could become more efficient from a total cost standpoint, to the degree that these decisions are price elastic. Moreover, modified (i.e., decreased) consumption can, in turn, affect planning decisions. Inclusion of externality costs in rates would thus be a consistent way to incorporate the valuation of external costs and the goals of such valuation in the planning and behavior of utilities and their customers.

The revenues collected from such a system could be placed in a fund that would be used to remediate the very problem that was the source of those revenues -- the emissions of pollutants. Such remediation could include: investments in pollution control, in environmental remediation, in conservation and renewables, in further research on environmental damages, damage costs, and control techniques, and other related needs. Of course, the design and administration of such a system would require careful thought, in order to ensure that it meets its objectives.

A similar approach that is receiving attention with regard to CO_2 is ascribing pollution taxes to energy purchase prices. This has the merit of being economy-wide, crossing all sectors in a *prima facie* consistent manner.

A Different Approach

In concluding, we should note that in one study (Tellus Institute 1990a), we adopted a different approach to these issues. In that study, we asked the following question: How much would it cost, over a thirty year planning horizon, to meet a predetermined air emissions limit (e.g., no net increase in emissions)? We then evaluated competing resource plans in regard to the costs that would be required to meet the emissions standard. In this "standards" approach, the focus is not on valuing air emissions externalities, as it has been in the work described above, but rather on the cost of avoiding such externalities. This distinction is important when we attempt to project the impact of imputing a value, e.g., $3.25 per pound of NO_x to energy resources. In general, use of such value does *not* mean that we will actually pay $3.25 to eliminate each pound of NO_x. Rather it means that we will pay up to $3.25 per ton to reduce NO_x emissions; some reductions will come at lower cost. Thus, to project the actual cost to society of using the $3.25 per pound estimate, we would need to project the distribution of NO_x reduction potential available for less than or equal to $3.25 per pound. The weighted average of these costs would be the correct cost to use for *projecting* the actual costs of meeting the emissions standard.

220

This **environmental standards** approach sets environmental targets and poses the question for resource planning: what is the least cost system (consistent with reliability and uncertainty considerations) to achieve *two*[21] objectives -- satisfying end-use energy requirements and meeting environmental targets. This least cost **energy/environment** planning approach places environmental objectives as an up-front consideration in energy planning, with the same analytical status as energy goals. There have been a number of recent instances of this approach, including our least cost planning study in Vermont, and recent studies of greenhouse gases reduction strategies (Kram and Okken 1989; Krause, Bach, and Koomey 1989).

Of course, in the energy/environment planning approach environmental targets (or constraints, in an optimization procedure) need to be specified. These must come, in large measure, from outside that analytical process. In setting those targets (e.g., for CO_2, or SO_x emissions) some notion of the damage or risk of damage must be involved. Thus, some assessment of environmental (and related) damages as well as public policy debate on the relative importance of those risks is necessary. The more general form of the energy/environment planning approach, then, would be to explore a range of environmental targets for a given pollutant, and to compare the costs of meeting energy requirements while satisfying the environmental constraint. A curve of energy costs could then be constructed are compared with a "curve" of potential damages. The damage curve can be both quantitative and qualitative (especially where there is great uncertainty), and may also refer to monetized costs where these can be appropriately and reliably estimated.

This analysis would thus compare costs to benefits in a way that could illuminate the issues and the decisions that would be required. The question of where the target should be set becomes, how much more are we willing to pay for our energy in order to avoid increases in certain sets of risks? This can be done for specific facilities as well as entire system plans. For example, if a small hydro facility falls within a least cost plan, one could remove it and find the new least cost plan. The higher cost of electricity can then be compared to the environmental damages or risks, with the policy question posed as one of willingness to pay.

Ultimately, then, this approach is linked with at least the idealized form of the revealed preferences approach, with certain key differences. Rather than using only existing revealed preferences of regulators, it would encourage explicit further exploration of all aspects of the cost/impact relationship, that are at best only implicit and imperfectly implicated in existing revealed preferences. Such exploration could

---

[21] *Actually, the environmental target can involve more than two objectives if more than one pollutant is addressed.*

221

reveal the shadow prices and the benefits of different levels of environmental protection, and inform the policy and planning processes.

222

ACKNOWLEDGEMENTS

The work described in this report has been funded by a number of sources. Our original work was sponsored by the Vermont Department of Public Service (Tellus Institute 1990a). Subsequent contracts with the Massachusetts Division of Energy Resources (Shimshak et al. 1990a,b,c), the California Public Utilities Commission (Tellus Institute 1990b), and the Rhode Island Division of Public Utilities and Carriers, the Rhode Island Division of Statewide Planning, and the Rhode Island Governor's Office of Energy Assistance (Tellus Institute 1990c) have allowed us to expand our efforts substantially. The cost estimates and views expressed in this document are those of the authors, however, and should not be attributed to these funding agencies.

SOURCES

American Petroleum Institute (API). 1989. *A Comparative Analysis of Stage II and Onboard Refueling Emissions Control*, Health and Environmental Affairs Department, July 3, 1989.

Benson, C. E. 1990. Arthur D. Little, personal communication, May 1, 1990.

Benson, C. E., G. D. Chittick, and R. P. Wilson. 1988. *Selective Catalytic NO_x Reduction Technology for Cogeneration Plants*, Prepared for the New England Cogeneration Association by Arthur D. Little, Inc., Cambridge, Massachusetts.

Blok, K., C. Hendriks, and W. C. Turkenburg. 1989. "The role of carbon dioxide recovery in the reduction of the greenhouse effect", paper presented at the IEA/OECD Expert seminar on energy technologies for reducing emissions of greenhouse gases (April 12-14, 1989), Paris.

California Energy Commission (CEC). 1989. "Staff Recommendations for Generic Power Plant Emissions Factors (Final Version)", August 1989.

California Energy Commission (CEC). 1990. "Committee Order for Final Policy Analysis", Docket No. 88-ER-8 (the 1990 Electricity Report), March 27, 1990.

Calwell, Chris. 1990. "Valuing Reductions in Carbon Dioxide Emissions", NRDC/Sierra Club Written Testimony for the California Energy Commission Electricity Report 90, January 11, 1990.

Chernick, Paul and Emily Caverhill. 1989. *The Valuation of Externalities from Energy Production, Delivery, and Use, Fall 1989 Update*, a Report to the Boston Gas Company, December 22, 1989.

Chernick, Paul and Emily Caverhill. 1990. "Report to the Boston Gas Company on Including Externalities in 89-239", April 12, 1990, Boston, Massachusetts.

Council of Economic Advisors. 1990. *Economic Report of the President/Annual Report of the Council of Economic Advisers*, U.S. Government Printing Office, Washington, D.C., February, 1990.

Denny Technical Services. 1990. *Clean Air Act Legislation Cost Evaluation*, prepared for The Business Roundtable, January 1990, Raleigh, North Carolina.

224

ECO Northwest, Shapiro and Associates, and Seton, Johnson, and Odell. 1984. *Economic Analysis of the Environmental Effects of a Combustion-Turbine Generating Station at Frederickson Industrial Park, Pierce County, Washington*, Final Report submitted to the Bonneville Power Administration under contract with United States Department of Energy, Portland, OR.

ECO Northwest, Shapiro and Associates, and Seton, Johnson, and Odell. 1986. *Estimating Environmental Costs and Benefits for Five Generating Resource.* Final Report and Technical Appendices submitted to the Bonneville Power Administration under contract with United States Department of Energy, Portland, OR.

ECO Northwest, Shapiro and Associates, and Seton, Johnson, and Odell. 1987. *Generic Coal Study: Quantification and Valuation of Environmental Impacts*, Report submitted to the Bonneville Power Administration under contract with United States Department of Energy, Portland, OR.

Electric Utility Week. 1990 "Senate Clean Air Bill Fixes Some Utility Concerns", page 1, April 9, 1990.

Electric World. 1990. Dispatches, p. 29, April 1990.

Environmental Protection Agency (EPA). 1984. *The Cost Digest: Cost Summaries of Selected Environmental Controls.*

ENSR. 1990. *New Source Review Application for The Proposed Repowering of the Manchester Street Station (Revised)*, report to the Narragansett Electric Company and the New England Power Company, May 1990.

Fritsche, U. and L. Rausch. 1989. *Total-Emission-Model for Integrated Systems (TEMIS)*, ÖKO-Institut, Darmstadt, Federal Republic of Germany.

Hall, Jane et al. 1989. *Economic Assessment of the Health Benefits in the South Coast Air Basin, from Improvements in Air Quality*, Final Report to the South Coast Air Quality Management District, Contract No. 5685, June 1989.

Hohmeyer, Olav. 1988. *Social Costs of Energy Consumption: External Effects of Electricity Generation in the Federal Republic of Germany*, Springer-Verlag, New York.

Kram, T. and P. A. Okken. 1989. "Two 'Low CO_2' Energy Scenarios for the Netherlands", paper presented at the IEA/OECD Expert seminar on energy technologies for reducing emissions of greenhouse gases (April 12-14, 1989), Paris.

225

Krause, Florentin, Wilfrid Bach. and Jon Koomey. 1989. *Energy Policy in the Greenhouse, Volume One, From Warming Fate to Warming Limit: Benchmarks for a Global Climate Convention*, International Project for Sustainable Energy Paths, El Cerrito, California, September, 1989.

Lashof, Daniel A. and Dilip R. Ahuja. 1990. Relative contributions of greenhouse gas emissions to global warming, *Nature 344*: 529-531, April 5, 1990.

Massachusetts Department of Environmental Quality Engineering (MA DEQE). 1989. *Stage II Gasoline Vapor Recovery Program: Background Information and Technical Support Document*, for public hearings on the proposed amendments to 310 CMR 7.00, Commonwealth of Massachusetts, January, 1989.

Massachusetts Department of Environmental Quality Engineering (MA DEQE). 1990. "Supplemental Comments of Division of Air Quality on environmental externalities for DPU #89-239", May 9, 1990.

McVay, Doug. 1990. Rhode Island Department of Environmental Management, personal communication, May 1, 1990.

New England Electric System (NEES). 1990. *Integrating Environmental Externalities into Resource Planning at New England Electric*, study prepared by Temple, Barker, and Sloane.

NY SEO, NY DPS, and NY DEC. 1989a. "Air Impacts/Electricity" in *(Draft) New York State Energy Plan, Staff Report Volume IV: Electricity Issues*. Albany, New York.

NY SEO, NY DPS, and NY DEC. 1989b. "Environmental Externalities" in *(Draft) New York State Energy Plan, Staff Report Volume IV: Electricity Issues*. Albany, New York.

Office of Technology Assessment (OTA). 1989. *Catching Our Breath: Next Steps for Reducing Urban Ozone*, U.S Government Printing Office, Washington D.C., July 1989.

Organisation for Economic Co-operation and Development (OECD). 1989. *Environmental Policy Benefits: Monetary Valuation*, Paris, France.

Pace University Center for Environmental Legal Studies et al. 1990. *Draft Final Report: Environmental Externality Costs From Electric Utility Operations*, a Report to the New York State Energy Research and Development Authority and the U.S. Department of Energy, February 28, 1990.

226

Pechan, E. H. and Associates. 1988. *National Assessment of VOC, CO, and NO_x Controls, Emissions, and Costs*, prepared for the U.S. EPA, September 1988, Springfield, Virginia.

Pechan, E. H. and Associates. 1990. *Ozone Nonattainment Analysis: A Comparison of Bills*, prepared for the U.S. EPA, January 1990, Springfield, Virginia.

Putta, Sury N. 1989. "Competition in Electric Generation -- Environmental Externalities", paper presented to the Power Planning Committee of the New England Governors Conference (October 1989), Boston, MA.

Ramanathan, V., Cicerone, R.J., Singh, H.B., and J.T. Kiehl. *J. geophys. Res 90*: 5547-5566.

Rotmans, J. and M.G.J. den Elzen. 1990. "Temperature Increasing Potentials (TIPS) for Greenhouse Gases", rapport nr. 222901001, RIVM, Bilthoven, The Netherlands, March 1990.

Schilberg, Gayatri, Jeff Nahigan, and William B. Marcus. 1989. "Review of CEC Staff's Revised 'Valuing Emissions Reductions for Electricity Report 90' Staff Issue Report #3R", prepared for the Independent Energy Producers Association, December 5, 1989.

Sedjo, Roger A. and Solomon, Allen M. 1989. "Climate and Forests", in Norman J. Rosenberg, William E. Easterling, Pierre R. Crosson, and Joel Darmstadter, Editors *Greenhouse Warming: Abatement and Adaptation*. Resources for the Future, Washington, D.C.

Shimshak, Rachel, Bruce Biewald, Harvey Salgo, Donald Marron, and Steve Bernow. 1990a. "Comments of the Division of Energy Resources", presented before the Massachusetts Department of Public Utilities, Case No. DPU 86-36-G and DPU 89-239, February 23, 1990.

Shimshak, Rachel, Bruce Biewald, Harvey Salgo, Donald Marron, and Steve Bernow. 1990b. "Comments of the Division of Energy Resources on Environmental Externalities", presented before the Massachusetts Department of Public Utilities, Case No. DPU 86-36-G and DPU 89-239, March 2, 1990.

Shimshak, Rachel, Bruce Biewald, Harvey Salgo, Donald Marron, and Steve Bernow. 1990c. "Final Comments of the Division of Energy Resources", presented before the Massachusetts Department of Public Utilities, Case No. DPU 86-36-G and DPU 89-239, May 4, 1990.

Sidebotham, George W. and Robert H. Williams. 1990. "Draft: Technology and Economics of $_x$ Control for Stationary Gas Turbines", Center for Energy and Environmental Studies, Princeton University, Princeton, New Jersey, February, 1990.

South Coast Air Quality Management District (SCAQMD). 1989. *Air Quality Management Plan, 1989 Revision: Final Appendix IV-A, Tier I, Tier II, and Contingency Control Measures*, March 1989.

South Coast Air Quality Management District (SCAQMD) and Southern California Association of Governments (SCAG). 1989. *Air Quality Management Plan: South Coast Air Basin, Executive Summary*, March 1989.

Steinberg, Cheng, and Horn. 1984. *A Systems Study for the Removal, Recovery, and Disposal of Carbon Dioxide from Fossil Fuel Power Plants in the U.S.*, Brookhaven National Laboratories.

Steudler, P.A. et al. 1989. Influence of nitrogen fertilization on methane uptake in temperate forest soils, *Nature 341:* 314-315, September 28, 1989.

Tellus Institute. 1990a. *The Role of Hydro-Quebec Power in a Least-Cost Resource Plan for Vermont.* A Report to the Vermont Department of Public Service, January 19, 1990.

Tellus Institute. 1990b. *Alternatives to Interstate Gas Pipeline Projects*, a Report to the California Public Utilities Commission, forthcoming.

Tellus Institute. 1990c. *Evaluation of Repowering the Manchester Street Station*, A Report to the Rhode Island Division of Public Utilities and Carriers, Rhode Island Division of Statewide Planning, and Rhode Island Governor's Office of Energy Assistance, forthcoming.

Therkelsen, Robert L. 1989. "Valuing Emissions Reductions for Electricity Report 90", California Energy Commission Staff Paper #3R, November 21, 1989.

United States Department of Energy (U.S. DOE). 1988. *Energy Technologies and the Environment*, Washington, D.C.

228

On Elasticities in the RMA Transportation Model

Hilke Kayser

April 1991

Large portions of a country's energy consumption are used for transportation purposes. In order to forecast future energy demands with some degree of accuracy, and to simulate the effects of public policies on the demand for transportation energy, it is therefore important to understand what determines the demand for the various fuels . Elasticities measure the responsiveness of a variable such as the demand for gasoline to changes in policy variables such as income and prices. The price elasticity of demand, for example, is defined as the ratio of the percentage change in the quantity demanded to a percentage change in the price. Elasticities are usually estimated from historic data by running time series regressions. Assuming that consumers' preferences are not changing significantly over time, the estimated elasticity values can then be used in forecast models or simulation models to predict future quantities and to evaluate available policy options.

A great number of models have been developed to estimate the demand for gasoline and the various elasticities for the United States and some Western European countries. Two approaches are commonly found in the literature. A straightforward approach observes that the demand for each of the fuel types is just a function of the real price of that fuel (P_f), real per capita income (Y) and the population (POP)

$$FUEL_t = f(P_{ft}, Y_t, POP_t) \qquad (1)$$

Equation (2) is usually estimated by ordinary least squares (OLS) on a log linear regression function of the kind:

$$\log(FUEL_t) = a+b1*\log(P_{ft})+b2*\log(Y_t)+b3*\log(POP_t)+e_t \qquad (2)$$

The results of this regression can directly be interpreted as the price elasticity of the demand for fuel type i (b1), and the income elasticity of that fuel type (b2). Various studies run alternative regressions that include additional variables without adding explanatory power or improving the goodness to fit. Other functional forms are also tested but do not tend to outperform the specification of equation (3). Results from some of the studies done for the demand of gasoline using this approach are listed in table 1.

229

Table 1

Study		$E_{GASOLINE,Y}$ LR	$E_{GASOLINE,Y}$ SR	$E_{GASOLINE,P}$ LR	$E_{GASOLINE,P}$ SR
Dahl		1.17	0.12	-0.2	-0.98
Baltagi,Griffin	US_{ols}	0.89		-0.9	
	US_{gls}	0.55		-0.61	
Drollas	UK	1.29		-0.55	-0.28
	FRG	1.15		-0.82	-0.45
	F	1.08		-0.58	-0.44
	AU	1.02		-0.82	-0.52
	US	0.34		-0.73	-0.35
Rice,Frater	UK	0.71		-0.18	-0.99

An alternative approach looks at the components of fuel demand, namely the vehicle stock, the average annual vehicle usage, and the efficiency of the vehicle fleet. All of the models are based on the identity:

$$FUEL_{it} = VEH_{it} * DIST_{it} * LKM_{it} \qquad (3)$$

where $FUEL_{it}$ = consumption of fuel i in year t
$DIST_{it}$= average annual vehicles usage in km by fuel type i in year t
VEH_{it}= vehicle stock using fuel type i in t
LKM_{it}= efficiency (liters per 100 km or kilowatt hours)

This approach estimates each of the components separately and uses the relationship displayed in equation (3) to calculate fuel demands. Given the log linear form of the relationship of equation (3), income and price elasticities can be found by realizing that they are the sum of the three separate component elasticities

$$E_{FUEL,P} = E_{VEH,P} + E_{DIST,P} + E_{LKM,P}$$
$$E_{FUEL,Y} = E_{VEH,Y} + E_{DIST,Y} + E_{LKM,Y} \qquad (4)$$

Results from these kind of studies for the demand for gasoline are listed in table 2.

230

Table 2

Study		$E_{GASOLINE,Y}$ TOTAL	DIST	LKM	VEH	$E_{GASOLINE,P}$ TOTAL	DIST	LKM	VEH
Wildhorn		0.88	0	0	0.88	-0.78	-0.36	0.17	-0.25
Sweeney		0.82	0.82	0	0	-0.78	-0.06	0.72	0
Pindyck		0.96	0.66	0	0.30	-2.07	0	1.43	-0.64
Wheaton		1.26	0.54	-0.21	1.38	-0.74	-0.5	0.32	0.16
Gately	cars		0.92			-0.07	0.01		
	trucks		1.16			-0.04	0.01		

Elasticity values are needed to incorporate the effect of price and/or income changes on the demand for the various fuel types into the RMA transportation model. The RMA transportation model is a very disaggregate model with the individual's trip-making as the choice variable. Since the relationship between the number of trips taken by an individual and the number of vehicles per capita is very stable, trip-making can be viewed as a good proxy for the vehicle stock. Individuals decide on the number of trips to take, the average length of the trips and the mode by which the trips are made based on their economic well-being. To create a base case for 1989 for Romania or Czechoslovakia, data and/or educated assumptions are used on these variables as well as on the fuel shares of the various modes of transportation, the fuel efficiencies and the load factors of the different modes.

Changes in income or in the price of the fuels affect these variables but to a varying degree. We will assume that the variable that is most directly affected by price and income changes is the number of trips that an individual is taking. Fuel shares by mode are not affected because each of the different modes of transportation is run exclusively on one type of fuel so that no fuel shift should be expected. Load factors might change, but the responses are not likely to be large nor are they easily predictable with our present knowledge. Once more data become available, the responsiveness to income or price changes should be analyzed more thoroughly. Modal shares, on the other hand, have changed considerably in most countries as per capita income rises. While both public and private trip making are likely to increase with income, private travel usually increases more rapidly. This phenomenon is represented in the model by larger income elasticities for private travel than for public travel modes. The response of fuel efficiency to price and income changes has been studied and is used in the model.

How then do price and income changes affect the number of trips that an individual is going to make? The elasticity of trip-making can be estimated by using the relationships in equation (4). It should be kept in mind that trip-making here is used as a proxy

231

for the vehicle stock. [1]

$$E_{TRIPS,P}=E_{GASOLINE,P}-E_{LKM,P}-E_{DIST,P}$$
$$E_{TRIPS,Y}=E_{GASOLINE,Y}-E_{LKM,Y}-E_{DIST,Y}$$

We are initially assuming that $E_{DIST,Y} = 0$ and $E_{DIST,P} = 0$, i.e. that the average annual distance travelled is not affected by changes in the price or changes in income since this effect has been shown to be rather small. Ideally we can use the results from table 1 and 2 to make reasonable assumptions about the elasticity of trip-making since the component elasticities have been estimated and can be found in the literature. The estimated elasticities are based on data from the United States or from some Western European countries. Looking at the tables, we observe an enormous variation in the estimated elasticity values, especially with respect to the price elasticities found in the various publications. What values should be used in the RMA transportation model?

For the income elasticity of trip making we assumed a value of 1.0. There are a number of reasons for this choice. More recent studies have shown that the income responses have been significantly larger in the European countries than in the U.S. Drollas argues that this shows a different attitude towards cars. Americans consider the car more of a necessity than Europeans. Suburban living and lack of alternative ways of transportation result in less responsiveness to income changes. Furthermore, it has been shown that a large part of the income effect comes through an increased vehicle stock, an effect which is most likely going to be stronger in a country like Romania where car-ownership is still very low and where the demand in the past may have been suppressed largely due to limited supplies. This should translate directly into an increased number of trips taken.

For the price elasticity, we assumed a value of -0.1, which is at the lower end of the scale. Given that income is still relatively low in Romania, vehicles are rather large investments. It is probably save to assume that vehicle owners are among the higher income groups. Once the money is spent on a vehicle, price changes are probably not going to affect the actual use significantly.

---

[1] Since in Czechoslovakia and in Romania the number of trips by automobile were not known, initial estimates were derived by taking the overall quantity of a fuel used in transportation and dividing it by the fuel efficiency, the average trip length and the population. For gasoline the equation is

GAS/LKM/DIST/POP = TRIPS (per person)

BIBLIOGRAPHY

1) Baltagi, B.H. and J.M. Griffin,'US gasoline demand: what next?', The Energy Journal, Vol.5, No1, January 1984, pp.129-40.
2) Dahl, C.A.,'Do gasoline demand elasticities vary?', Land Economics, Vol.58, No3, August 1982, pp.373-82.
3) Difiglio, C.,K.G. Duleep and D.L. Greene,'Cost effectiveness of future fuel economy improvements', The Energy Journal, Vol.11, January 1990, pp.65-85.
4) Drollas, L.P.,'The demand for gasoline: further evidence', Energy Economics, Vol.6, No1, January 1984, pp.71-84.
5) Frater, P. and P. Rice,'The demand for petrol with explicit fuel efficiency effects: a UK study 1977-1986', Energy Economics, April 1989, pp.95-104.
6) Gately, D.,'The US demand for highway travel and motor fuel',The Energy Journal, Vol.11, No3, August 1990, pp.59-73.
7) Greene, D.L.,'CAFE or price?: an analysis of the effects of federal fuel economy regulations and gasoline price on new car MPG, 1978-1989', The Energy Journal, Vol.11, No3, August 1990, pp.37-57.
8) Hsing, Y.,'On the variable elasticity of the demand for gasoline: the case of the USA', Energy Economics, April 1990, pp.131-36.
9) Mayo, J.W. and J.E. Mathis,'The effectiveness of mandatory fuel efficiency standards in reducing the demand for gasoline', Applied Economics, Vol 20, 1988, pp.211-19.
10) Wheaton, W.C.,'The long-run structure of transportation and gasoline demand', The Bell Journal of Economics, Vol 13, 1982, pp.439-454.

The User's Guides, Models (on 3.5" disks) and Data Documentation for The Industrial Sector Energy Demand Model, The Transportation Sector Energy Demand Model, and the LEAP Model are provided under separate cover. (Notebooks provided to Romania included user's guides and data documentation.)

SCENARIO RESULTS FOR THE INDUSTRIAL MODEL

*OUTPUT SUMMARY:ROMANIAN INDUSTRIAL Scen A (Revised)

INDUSTRIAL ENERGY USE BY SUBSECTOR (TJ)

	1989	1990	1991	1992	1994	2000
Mining	2.15E+04	1.71E+04	1.69E+04	1.74E+0	1.81E+0	1.86E+0
Chemical	7.05E+05	2.97E+05	2.57E+05	2.42E+0	2.28E+0	2.49E+0
Ferr.Met.	3.37E+05	1.49E+05	1.24E+05	1.17E+0	1.13E+0	1.23E+0
NF metal	1.09E+05	3.89E+04	3.17E+04	3.09E+0	3.09E+0	3.34E+0
Mech.En	1.59E+05	1.37E+05	1.33E+05	1.42E+0	1.71E+0	2.69E+0
Construc	1.13E+05	7.46E+04	5.94E+04	5.34E+0	5.79E+0	8.17E+0
Forest Pr	9.75E+04	7.53E+04	7.31E+04	7.64E+0	8.42E+0	1.16E+0
Food Ind.	8.87E+04	7.07E+04	7.04E+04	7.35E+0	8.10E+0	1.10E+0
Other	1.49E+05	1.30E+05	1.30E+05	1.36E+0	1.47E+0	1.71E+0
TOTAL	1.78E+06	9.89E+05	8.95E+05	8.89E+0	9.31E+0	1.17E+0
(Combined categories for graphing)						
Metals	4.46E+05	1.88E+05	1.56E+05	1.48E+0	1.43E+0	1.57E+0
Min&For	1.19E+05	9.24E+04	9.01E+04	9.37E+0	1.02E+0	1.35E+0
Food&O	2.38E+05	2.01E+05	2.01E+05	2.10E+0	2.28E+0	2.80E+0

INDUSTRIAL FUEL USE BY FUEL TYPE (TJ)

Electric	1.79E+05	1.05E+05	9.32E+04	9.30E+0	1.00E+0	1.32E+0
Thermal	4.36E+05	2.59E+05	2.34E+05	2.33E+0	2.48E+0	3.21E+0
Coal	2.26E+05	1.21E+05	1.07E+05	1.06E+0	1.09E+0	1.34E+0
Petrol	9.34E+04	7.32E+04	7.23E+04	7.63E+0	8.21E+0	9.91E+0
Nat.Gas	8.47E+05	4.31E+05	3.89E+05	3.80E+0	3.92E+0	4.86E+0
Solar	0.00E+00	0.00E+00	0.00E+00	0.00E+0	0.00E+0	0.00E+0
Other	0.00E+00	0.00E+00	0.00E+00	0.00E+0	0.00E+0	0.00E+0
TOTAL	1.78E+06	9.89E+05	8.95E+05	8.89E+0	9.31E+0	1.17E+0

GROWTH RATE BY SECTOR

Mining	-10.00%	0.00%	2.00%	2.00%	0.50%
Chemical	-42.39%	-11.79%	-5.34%	-3.00%	1.50%
Ferr.Met.	-39.73%	-15.89%	-5.40%	-2.00%	1.50%
NF metals	-53.28%	-16.91%	-2.40%	-0.00%	1.30%
Mech.Eng.	-1.10%	-2.00%	7.20%	10.00%	7.80%
Construc.	-20.00%	-20.00%	-10.00%	4.20%	5.90%
Forest Pr	-3.00%	-0.00%	5.00%	5.00%	5.50%
Food Ind.	2.00%	2.00%	5.00%	5.00%	5.20%
Other	1.40%	1.00%	4.00%	4.00%	2.50%
TOTAL	-12.83%	-5.28%	1.62%	4.71%	4.98%
(Combined categories for graphing)					
Metals	-43.82%	-16.15%	-4.65%	-1.49%	1.45%
Min&For	-3.83%	-0.00%	4.67%	4.67%	4.98%
Food&Oth	1.69%	1.48%	4.48%	4.48%	3.82%

ENERGY INTENSITY BY SE (TJ/E6K)

Mining	2.06	1.82	1.80	1.81	1.81	1.81
Chemical	19.36	14.14	13.89	13.84	13.84	13.84
Ferr.Met.	10.88	8.00	7.89	7.90	7.90	7.90
NF metal	8.18	6.22	6.10	6.08	6.08	6.08
Mech.En	2.95	2.57	2.53	2.53	2.53	2.53
Construc	1.36	1.12	1.11	1.11	1.11	1.11
Forest Pr	1.26	1.00	0.97	0.97	0.97	0.97
Food Ind.	1.66	1.29	1.26	1.26	1.26	1.26
Other	2.55	2.19	2.17	2.18	2.18	2.18
TOTAL	4.26	2.71	2.59	2.53	2.42	2.27
(Combined categories for graphing)						
Metals	10.06	7.55	7.45	7.44	7.42	7.43
Min&For	1.35	1.09	1.07	1.06	1.06	1.03
Food&O	2.12	1.76	1.73	1.73	1.73	1.69

PERCENTAGE PRICE INCREASES FOR FUELS

Electric	112.0%	15.6%	4.1%	0.0%	0.0%
Thermal	112.0%	15.6%	4.1%	0.0%	0.0%
Coal	70.0%	0.0%	-1.2%	0.0%	0.0%
Petrol	53.0%	-2.6%	-8.7%	0.0%	0.0%
Nat.Gas	100.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%

PERCENTAGE SHARES OF INDUSTRIAL OUTPUT

Mining	2.50%	2.58%	2.73%	2.74%	2.60%	2.00%
Chemical	8.70%	5.75%	5.35%	4.99%	4.28%	3.50%
Ferr.Met.	7.40%	5.12%	4.54%	4.23%	3.70%	3.03%
NF metals	3.20%	1.71%	1.50%	1.45%	1.32%	1.06%
Mech.Eng.	12.90%	14.64%	15.14%	15.98%	17.63%	20.67%
Construc.	20.00%	18.35%	15.50%	13.73%	13.60%	14.33%
Forest Pr	18.50%	20.59%	21.73%	22.46%	22.58%	23.26%
Food Ind.	12.80%	14.98%	16.13%	16.67%	16.76%	16.97%
Other	14.00%	16.29%	17.37%	17.77%	17.53%	15.19%
(Combined categories for graphing)						
Metals	10.60%	6.83%	6.05%	5.67%	5.02%	4.09%
Min&For	21.00%	23.17%	24.46%	25.19%	25.18%	25.26%
Food&Oth	26.80%	31.26%	33.49%	34.44%	34.29%	32.16%

PERCENTAGE SHARES OF ENERGY USE

Mining	1.21%	1.73%	1.89%	1.95%	1.94%	1.59%
Chemical	39.59%	29.98%	28.71%	27.26%	24.48%	21.27%
Ferr.Met.	18.91%	15.08%	13.84%	13.20%	12.09%	10.51%
NF metals	6.15%	3.93%	3.54%	3.47%	3.31%	2.85%
Mech.Eng.	8.93%	13.86%	14.80%	15.94%	18.41%	22.96%
Construc.	6.37%	7.55%	6.63%	6.00%	6.22%	6.97%
Forest Pr	5.48%	7.61%	8.17%	8.59%	9.04%	9.91%
Food Ind.	4.98%	7.14%	7.86%	8.27%	8.70%	9.37%
Other	8.38%	13.13%	14.54%	15.31%	15.80%	14.57%
(Combined categories for graphing)						
Metals	25.06%	19.01%	17.38%	16.67%	15.41%	13.36%
Min&For	6.68%	9.34%	10.06%	10.54%	10.98%	11.49%
Food&Oth	13.36%	20.27%	22.41%	23.58%	24.50%	23.94%

GROSS INDUSTRIAL PRODUCT (Millions of Romanian Lei)

Mining	10460	9414	9414	9602	9990	10294
Chemical	36400	20971	18498	17511	16476	18015
Ferr.Met.	30962	18659	15694	14847	14259	15592
NF metals	13389	6255	5198	5073	5073	5482
Mech.Eng.	53974	53380	52313	56079	67856	106488
Construc.	83680	66944	53555	48200	52333	73817
Forest Pr	77404	75082	75082	78836	86917	119844
Food Ind.	53555	54626	55719	58505	64501	87430
Other	58576	59396	59990	62390	67481	78257
TOTAL	418400	364728	345462	351042	384886	515219
(Combined categories for graphing)						
Metals	44351	24914	20892	19920	19332	21074
Min&For	87864	84496	84496	88438	96907	130138
Food&Oth	112131	114022	115709	120894	131982	165687

236

********** ********** **********

* PRICING INPUT MODULE * CASE TITLE: Scen A (Revised)

********** ********** **********

TARGET INCREASES IN ENERGY PRICES (in Romanian Lei):

	Electric (Lei/MWH)	Thermal (Lei/Gc)	Coal (Lei/Mt)	Petrol (Lei/Mt)	Nat.Gas (Lei/m3)	Solar (Lei/GJ)	Other (Lei/GJ)
1990	2.12	2.12	1.70	1.53	2.00	1.00	1.00
1991	2.45	2.45	1.70	1.49	2.00	1.00	1.00
1992	2.55	2.55	1.68	1.36	2.00	1.00	1.00
1994	2.55	2.55	1.68	1.36	2.00	1.00	1.00
2000	2.55	2.55	1.68	1.36	2.00	1.00	1.00

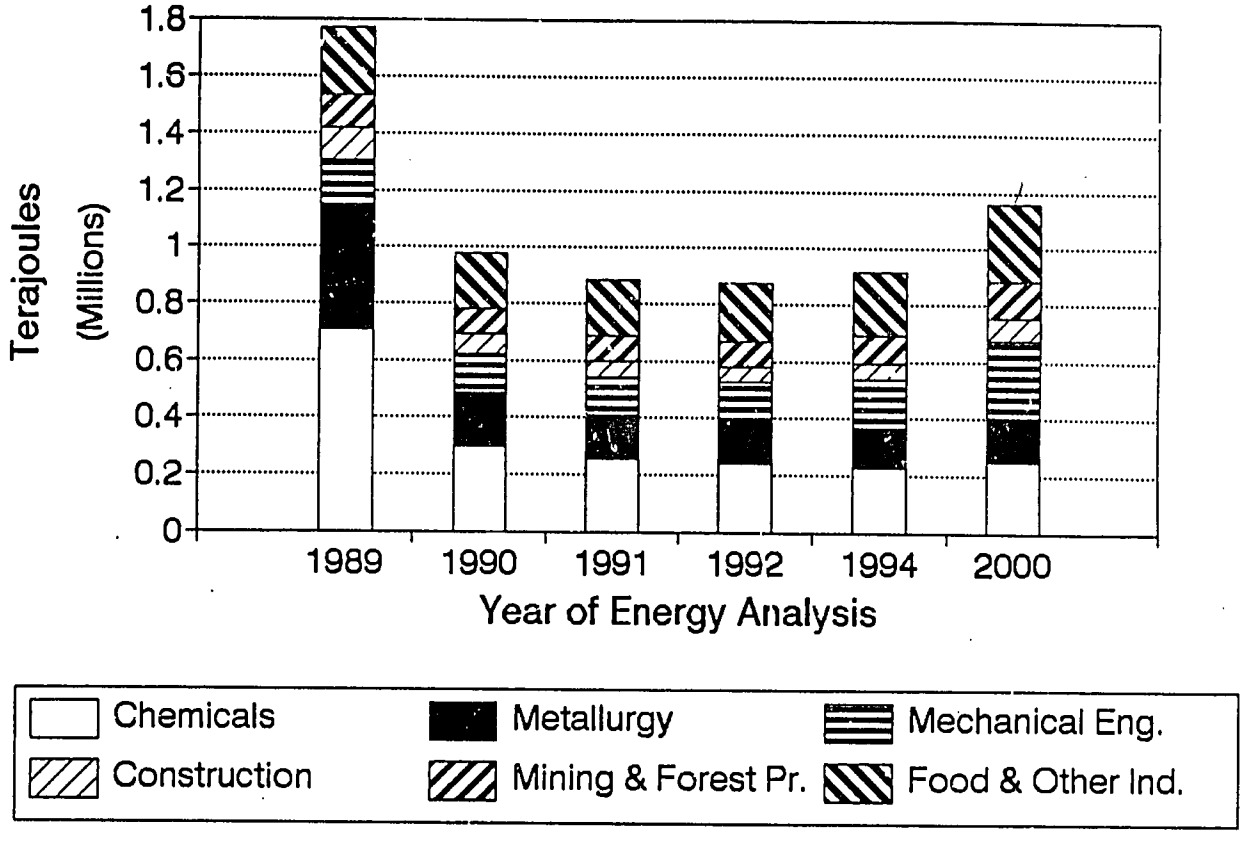
ENERGY PRICE RESPONSE FOR EACH SUBSECTOR AND FUEL TYPE:

	Electric	Thermal	Coal	Petrol	Nat.Gas	Solar	Other
Mining	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Chemical	-0.35	-0.35	-0.35	-0.40	-0.50	0.00	0.00
Ferr.Met.	-0.50	-0.50	-0.50	-0.50	-0.50	0.00	0.00
NF metals	-0.40	-0.40	-0.40	-0.40	-0.40	0.00	0.00
Mech.Eng.	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Construc.	-0.20	-0.20	-0.40	-0.20	-0.30	0.00	0.00
Forest Pr	-0.30	-0.30	-0.30	-0.40	-0.40	0.00	0.00
Food Ind.	-0.30	-0.30	-0.20	-0.40	-0.40	0.00	0.00
Other	-0.25	-0.25	-0.25	-0.25	-0.25	0.00	0.00

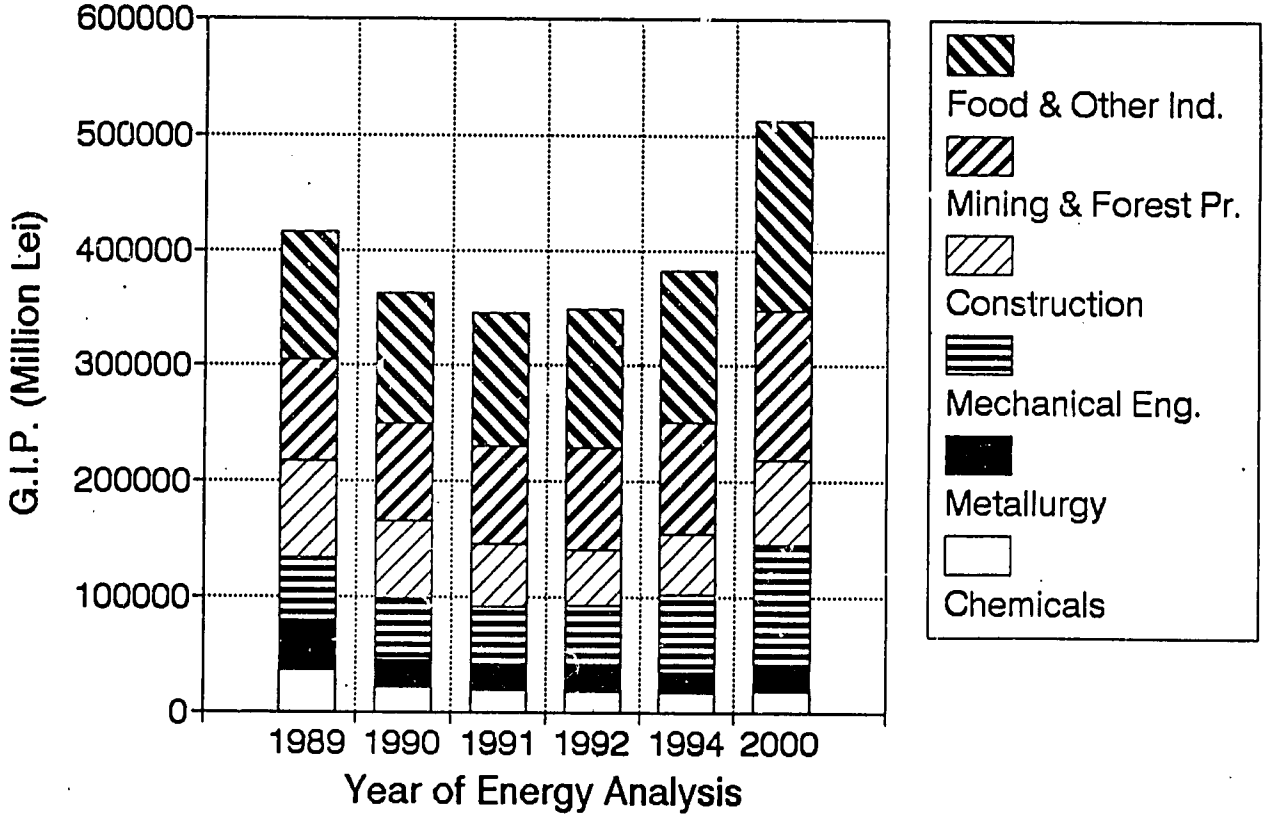
OUTPUT PRICE RESPONSE FOR EACH SUBSECTOR AND FUEL TYPE:

	Electric	Thermal	Coal	Petrol	Nat.Gas	Solar	Other
Mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical	-0.40	-0.40	0.00	-0.50	-0.50	0.00	0.00
Ferr.Met.	-0.40	-0.40	-0.30	-0.40	-0.40	0.00	0.00
NF metals	-0.50	-0.50	-0.30	-0.50	-0.50	0.00	0.00
Mech.Eng.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forest Pr	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food Ind.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00

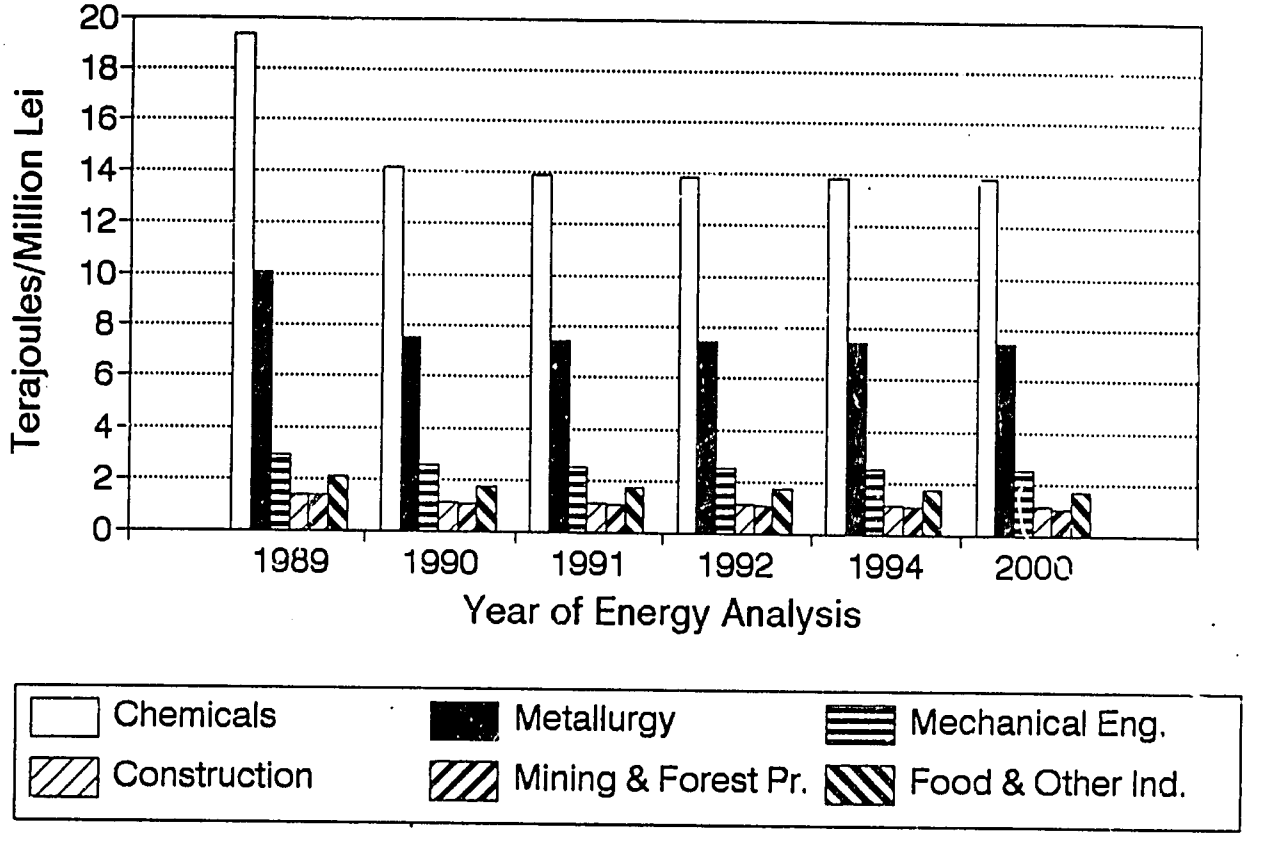
Energy Consumption in Romanian Industry



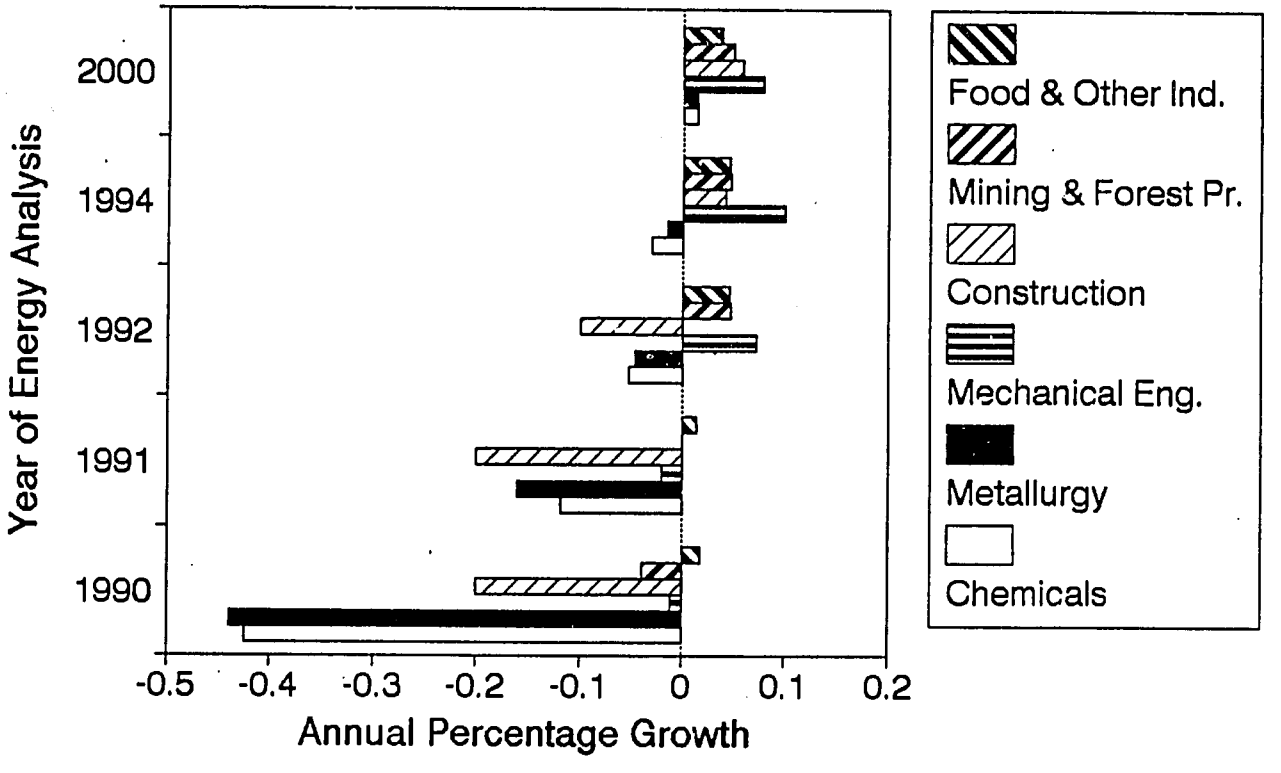
Gross Industrial Product in Romanian Industry



Energy Intensity in Romanian Industry



Growth Rates in Romanian Industry



*OUTPUT SUMMARY:ROMANIAN INDUSTRIAL Scenario B (High)

INDUSTRIAL ENERGY USE BY SUBSECTOR (TJ)

	1989	1990	1991	1992	1994	2000
Mining	2.15E+04	1.71E+04	1.66E+04	1.70E+0	1.77E+0	1.82E+0
Chemical	7.05E+05	3.17E+05	2.54E+05	2.42E+0	2.28E+0	2.49E+0
Ferr.Met.	3.37E+05	1.49E+05	1.12E+05	1.03E+0	9.86E+0	1.08E+0
NF metal	1.09E+05	3.89E+04	2.89E+04	2.83E+0	2.83E+0	3.06E+0
Mech.En	1.59E+05	1.37E+05	1.30E+05	1.39E+0	1.68E+0	2.64E+0
Construc	1.13E+05	7.90E+04	6.16E+04	4.99E+0	5.42E+0	7.64E+0
Forest Pr	9.75E+04	8.51E+04	8.25E+04	8.66E+0	9.55E+0	1.32E+0
Food Ind.	8.87E+04	7.84E+04	7.71E+04	8.10E+0	8.93E+0	1.21E+0
Other	1.49E+05	1.30E+05	1.27E+05	1.32E+0	1.43E+0	1.66E+0
TOTAL	1.78E+06	1.03E+06	8.89E+05	8.79E+0	9.23E+0	1.16E+0
(Combined categories for graphing)						
Metals	4.46E+05	1.88E+05	1.41E+05	1.31E+0	1.27E+0	1.38E+0
Min&For	1.19E+05	1.02E+05	9.91E+04	1.04E+0	1.13E+0	1.50E+0
Food&O	2.38E+05	2.08E+05	2.04E+05	2.13E+0	2.32E+0	2.87E+0

INDUSTRIAL FUEL USE BY FUEL TYPE (TJ)

Electric	1.79E+05	1.06E+05	9.05E+04	9.10E+0	9.84E+0	1.30E+0
Thermal	4.36E+05	2.67E+05	2.32E+05	2.35E+0	2.50E+0	3.26E+0
Coal	2.26E+05	1.22E+05	9.97E+04	9.44E+0	9.80E+0	1.21E+0
Petrol	9.34E+04	7.38E+04	7.13E+04	7.38E+0	7.96E+0	9.61E+0
Nat.Gas	8.47E+05	4.62E+05	3.95E+05	3.85E+0	3.97E+0	4.92E+0
Solar	0.00E+00	0.00E+00	0.00E+00	0.00E+0	0.00E+0	0.00E+0
Other	0.00E+00	0.00E+00	0.00E+00	0.00E+0	0.00E+0	0.00E+0
TOTAL	1.78E+06	1.03E+06	8.89E+05	8.79E+0	9.23E+0	1.16E+0

GROWTH RATE BY SECTOR

Mining	-10.00%	0.00%	2.00%	2.00%	0.50%
Chemical	-42.39%	-15.72%	-4.55%	-3.00%	1.50%
Ferr.Met.	-39.73%	-19.32%	-6.42%	-2.00%	1.50%
NF metals	-53.28%	-20.93%	-1.96%	0.00%	1.50%
Mech.Eng.	-2.10%	-2.00%	7.20%	10.00%	7.80%
Construc.	-20.00%	-20.00%	-19.00%	4.20%	5.90%
Forest Pr	-3.00%	0.00%	5.00%	5.00%	5.50%
Food Ind.	2.00%	2.00%	5.00%	5.00%	5.20%
Other	1.40%	1.00%	4.00%	4.00%	2.50%
TOTAL	-12.83%	-5.75%	0.25%	4.75%	4.98%
(Combined categories for graphing)					
Metals	-43.82%	-19.73%	-5.32%	-1.49%	1.45%
Min&For	-3.83%	0.00%	4.67%	4.67%	4.98%
Food&Oth	1.69%	1.48%	4.48%	4.48%	3.82%

ENERGY INTENSITY BY SE (TJ/E6K)

Mining	2.06	1.82	1.77	1.77	1.77	1.77
Chemical	19.36	15.11	14.35	14.38	14.38	14.38
Ferr.Met.	10.88	8.00	7.42	7.29	7.29	7.29
NF metal	8.18	6.22	5.85	5.84	5.84	5.84
Mech.En	2.95	2.57	2.48	2.48	2.48	2.48
Construc	1.36	1.18	1.15	1.15	1.15	1.15
Forest Pr	1.26	1.13	1.10	1.10	1.10	1.10
Food Ind.	1.66	1.43	1.38	1.38	1.38	1.38
Other	2.55	2.19	2.12	2.12	2.12	2.12
TOTAL	4.26	2.83	2.59	2.55	2.44	2.30
(Combined categories for graphing)						
Metals	10.06	7.55	7.03	6.92	6.91	6.91
Min&For	1.35	1.21	1.17	1.17	1.17	1.15
Food&O	2.12	1.83	1.76	1.76	1.76	1.73

PERCENTAGE PRICE INCREASES FOR FUELS

Electric	112.0%	29.7%	0.0%	0.0%	0.0%
Thermal	112.0%	29.7%	0.0%	0.0%	0.0%
Coal	70.0%	15.3%	8.2%	0.0%	0.0%
Petrol	53.0%	3.9%	-2.5%	0.0%	0.0%
Nat.Gas	100.0%	10.0%	-0.9%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%

PERCENTAGE SHARES OF INDUSTRIAL OUTPUT

Mining	2.50%	2.58%	2.74%	2.79%	2.64%	2.03%
Chemical	8.70%	5.75%	5.14%	4.89%	4.20%	3.43%
Ferr.Met.	7.40%	5.12%	4.38%	4.09%	3.58%	2.92%
NF metals	3.20%	1.71%	1.44%	1.41%	1.28%	1.04%
Mech.Eng.	12.90%	14.64%	15.22%	16.27%	17.95%	21.04%
Construc.	20.00%	18.35%	15.58%	12.59%	12.46%	13.13%
Forest Pr	18.50%	20.59%	21.84%	22.88%	22.99%	23.68%
Food Ind.	12.80%	14.98%	16.21%	16.98%	17.06%	17.27%
Other	14.00%	16.29%	17.45%	18.11%	17.85%	15.46%
(Combined categories for graphing)						
Metals	10.60%	6.83%	5.82%	5.50%	4.86%	3.96%
Min&For	21.00%	23.17%	24.58%	25.66%	25.63%	25.71%
Food&Oth	26.80%	31.26%	33.66%	35.08%	34.91%	32.74%

PERCENTAGE SHARES OF ENERGY USE

Mining	1.21%	1.66%	1.87%	1.93%	1.92%	1.57%
Chemical	39.59%	30.72%	28.53%	27.58%	24.72%	21.42%
Ferr.Met.	18.91%	14.46%	12.57%	11.68%	10.68%	9.25%
NF metals	6.15%	3.77%	3.26%	3.22%	3.07%	2.63%
Mech.Eng.	8.93%	13.29%	14.59%	15.79%	18.20%	22.63%
Construc.	6.37%	7.66%	6.93%	5.68%	5.87%	6.56%
Forest Pr	5.48%	8.25%	9.28%	9.85%	10.34%	11.30%
Food Ind.	4.98%	7.60%	8.67%	9.21%	9.68%	10.39%
Other	8.38%	12.59%	14.30%	15.05%	15.51%	14.25%
(Combined categories for graphing)						
Metals	25.06%	18.23%	15.83%	14.90%	13.75%	11.88%
Min&For	6.68%	9.91%	11.15%	11.78%	12.26%	12.87%
Food&Oth	13.36%	20.19%	22.97%	24.27%	25.19%	24.64%

GROSS INDUSTRIAL PRODUCT (Millions of Romanian Lei)

Mining	10460	9414	9414	9602	9990	10294
Chemical	36400	20971	17673	16862	15865	17348
Ferr.Met.	30962	18659	15054	14087	13529	14794
NF metals	13389	6255	4946	4849	4849	5240
Mech.Eng.	53974	53380	52313	56079	67856	106488
Construc.	83680	66944	53555	43380	47100	66435
Forest Pr	77404	75082	75082	78836	86917	119844
Food Ind.	53555	54626	55719	58505	64501	87430
Other	58576	59396	59990	62390	67481	78257
TOTAL	418400	364728	343745	344590	378088	506130
(Combined categories for graphing)						
Metals	44351	24914	20000	18936	18378	20033
Min&For	87864	84496	84496	88438	96907	130138
Food&Oth	112131	114022	115709	120894	131982	165687

******** ******** ********

* PRICING INPUT MODULE CASE TITLE: Scenario B (High)

******** ******** ********

TARGET INCREASES IN ENERGY PRICES (in Romanian Lei):

	Electric (Lei/MW	Thermal (Lei/Gc)	Coal (Lei/Mt)	Petrol (Lei/Mt)	Nat.Gas (Lei/m3)	Solar (Lei/GJ)	Other (Lei/GJ)
1990	2.12	2.12	1.70	1.53	2.00	1.00	1.00
1991	2.75	2.75	1.96	1.59	2.20	1.00	1.00
1992	2.75	2.75	2.12	1.55	2.18	1.00	1.00
1994	2.75	2.75	2.12	1.55	2.18	1.00	1.00
2000	2.75	2.75	2.12	1.55	2.18	1.00	1.00

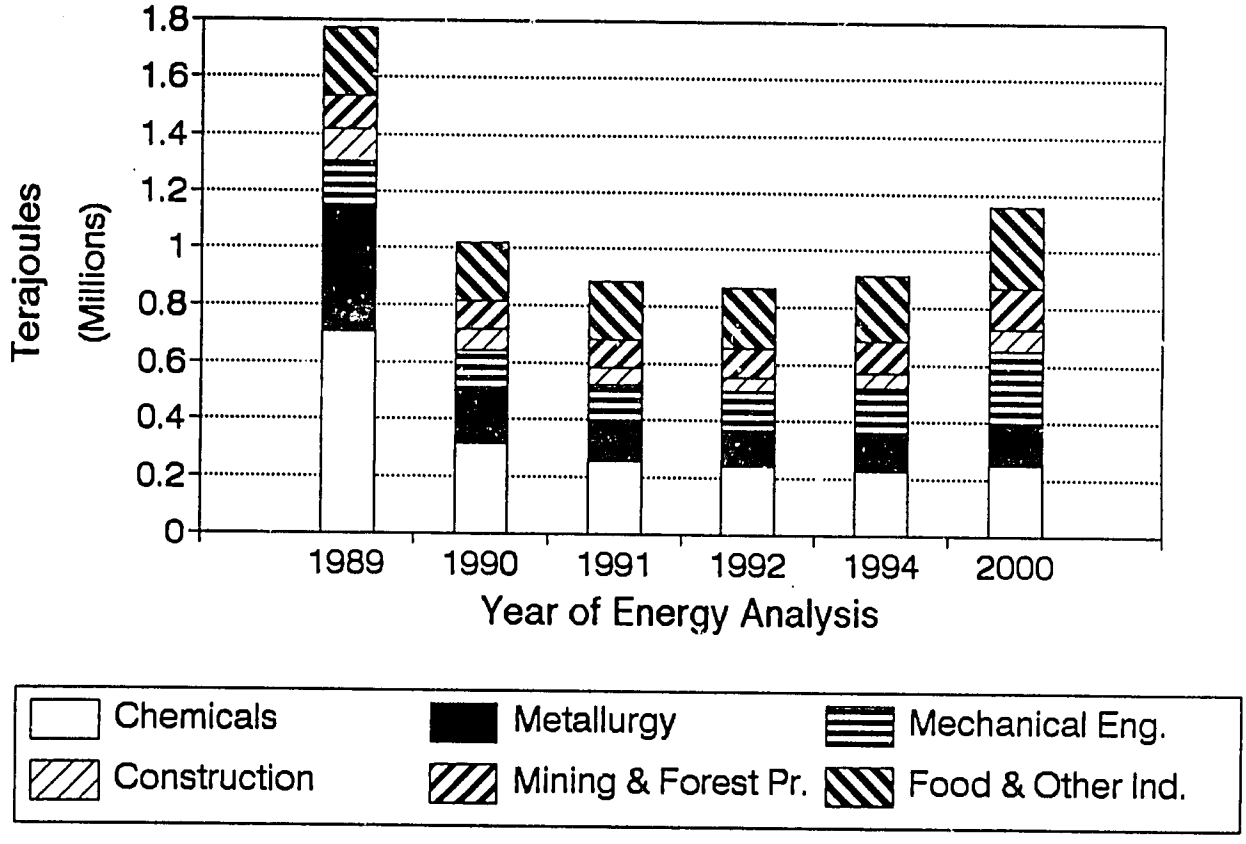
ENERGY PRICE RESPONSE FOR EACH SUBSECTOR AND FUEL TYPE:

	Electric	Thermal	Coal	Petrol	Nat.Gas	Solar	Other
Mining	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Chemical	-0.35	-0.35	-0.35	-0.35	-0.35	0.00	0.00
Ferr.Met.	-0.50	-0.50	-0.50	-0.50	-0.50	0.00	0.00
NF metal	-0.40	-0.40	-0.40	-0.40	-0.40	0.00	0.00
Mech.En	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Construc.	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Forest Pr	-0.15	-0.15	-0.15	-0.15	-0.15	0.00	0.00
Food Ind.	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Other	-0.25	-0.25	-0.25	-0.25	-0.25	0.00	0.00

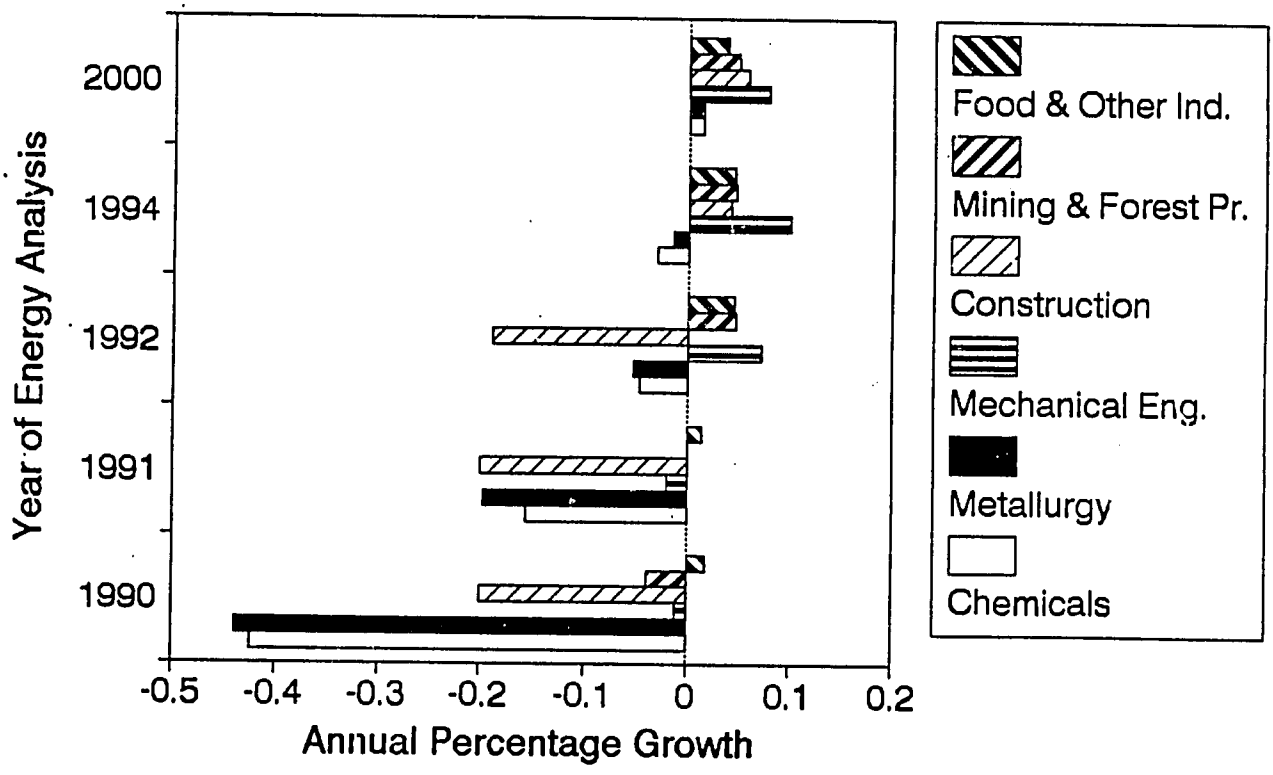
OUTPUT PRICE RESPONSE FOR EACH SUBSECTOR AND FUEL TYPE:

	Electric	Thermal	Coal	Petrol	Nat.Gas	Solar	Other
Mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical	-0.40	-0.40	0.00	-0.50	-0.50	0.00	0.00
Ferr.Met.	-0.40	-0.40	-0.30	-0.40	-0.40	0.00	0.00
NF metal	-0.50	-0.50	-0.30	-0.50	-0.50	0.00	0.00
Mech.En	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forest Pr	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food Ind.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00

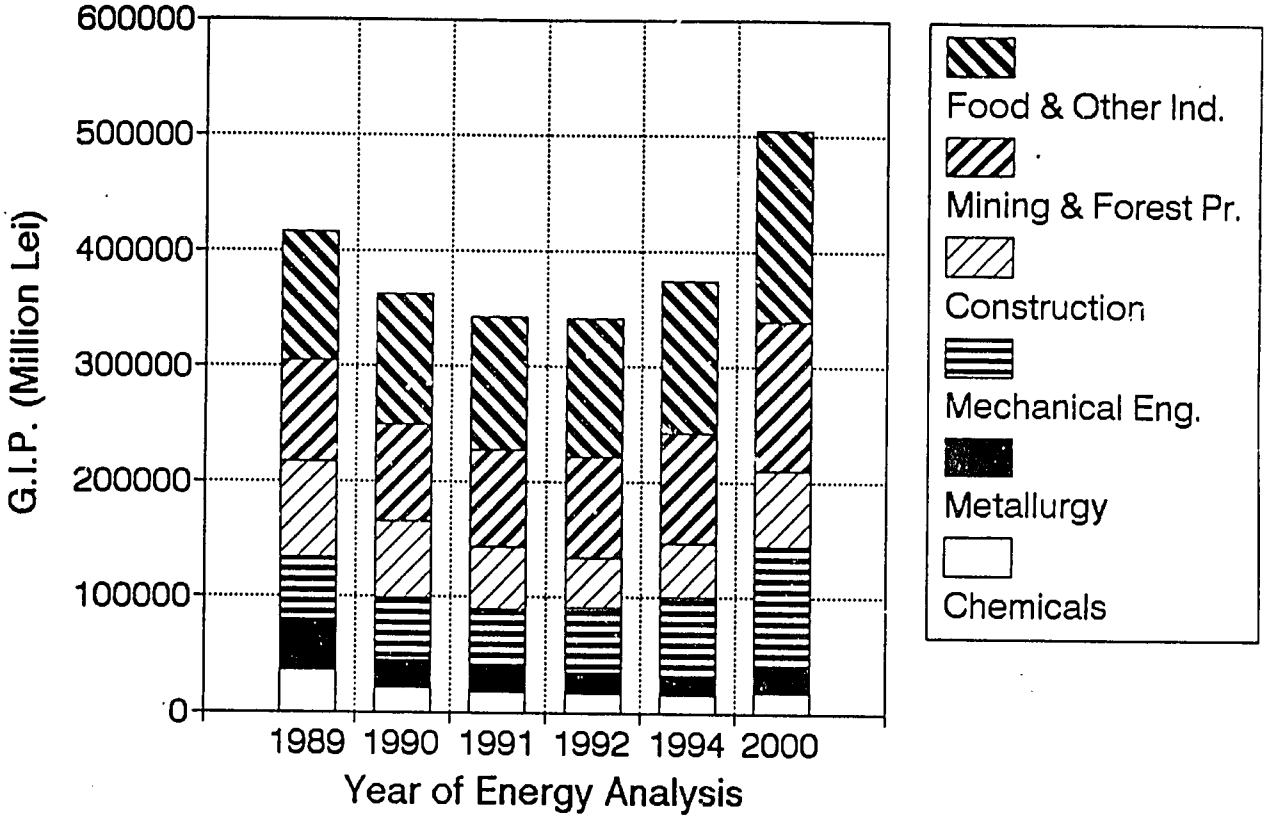
Energy Consumption in Romanian Industry



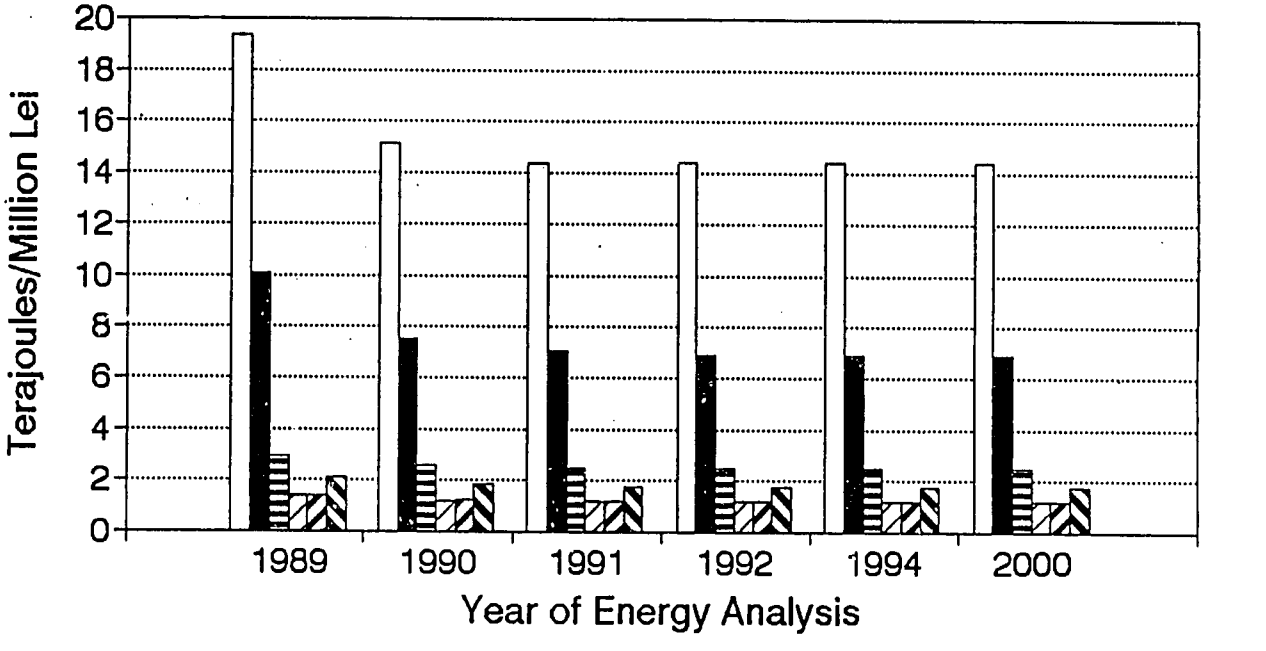
Growth Rates in Romanian Industry



Gross Industrial Product in Romanian Industry



Energy Intensity in Romanian Industry



*OUTPUT SUMMARY:ROMANIAN INDUSTRIAL Scenario C (Low)

INDUSTRIAL ENERGY USE BY SUBSECTOR (TJ)

	1989	1990	1991	1992	1994	2000
Mining	2.15E+04	1.71E+04	1.73E+04	1.78E+0	1.85E+0	1.91E+0
Chemical	7.05E+05	3.17E+05	3.53E+05	3.64E+0	3.43E+0	3.75E+0
Ferr.Met.	3.37E+05	1.49E+05	1.39E+05	1.37E+0	1.32E+0	1.44E+0
NF metal	1.09E+05	3.89E+04	3.96E+04	4.19E+0	4.19E+0	4.53E+0
Mech.En	1.59E+05	1.37E+05	1.37E+05	1.49E+0	1.80E+0	2.83E+0
Construc	1.13E+05	7.90E+04	6.69E+04	6.14E+0	6.67E+0	9.41E+0
Forest Pr	9.75E+04	8.51E+04	8.56E+04	9.07E+0	1.00E+0	1.38E+0
Food Ind.	8.87E+04	7.84E+04	8.24E+04	8.79E+0	9.69E+0	1.31E+0
Other	1.19E+05	1.30E+05	1.35E+05	1.43E+0	1.55E+0	1.79E+0
TOTAL	1.78E+06	1.03E+06	1.06E+06	1.09E+0	1.13E+0	1.41E+0
(Combined categories for graphing)						
Metals	4.46E+05	1.88E+05	1.79E+05	1.79E+0	1.74E+0	1.89E+0
Min&For	1.19E+05	1.02E+05	1.03E+05	1.08E+0	1.19E+0	1.57E+0
Food&O	2.38E+05	2.08E+05	2.17E+05	2.31E+0	2.51E+0	3.11E+0

INDUSTRIAL FUEL USE BY FUEL TYPE (TJ)

Electric	1.79E+05	1.06E+05	1.01E+05	1.04E+0	1.12E+0	1.45E+0
Thermal	4.36E+05	2.67E+05	2.60E+05	2.70E+0	2.85E+0	3.67E+0
Coal	2.26E+05	1.22E+05	1.12E+05	1.11E+0	1.15E+0	1.40E+0
Petrol	9.34E+04	7.38E+04	7.41E+04	7.75E+0	8.33E+0	1.00E+0
Nat.Gas	8.47E+05	4.62E+05	5.09E+05	5.30E+0	5.39E+0	6.56E+0
Solar	0.00E+00	0.00E+00	0.00E+00	0.00E+0	0.00E+0	0.00E+0
Other	0.00E+00	0.00E+00	0.00E+00	0.00E+0	0.00E+0	0.00E+0
TOTAL	1.78E+06	1.03E+06	1.06E+06	1.09E+0	1.13E+0	1.41E+0

GROWTH RATE BY SECTOR

Mining	-10.00%	0.00%	2.00%	2.00%	0.50%
Chemical	-42.39%	2.25%	-0.29%	-3.00%	1.50%
Ferr.Met.	-39.73%	-11.50%	-3.60%	-2.00%	1.50%
NF metals	-53.28%	-5.93%	2.24%	0.00%	1.30%
Mech.Eng.	-1.10%	-2.00%	7.20%	10.00%	7.80%
Construc.	-20.00%	-20.00%	-10.00%	4.20%	5.90%
Forest Pr	-3.00%	0.00%	5.00%	5.00%	5.50%
Food Ind.	2.00%	2.00%	5.00%	5.00%	5.20%
Other	1.40%	1.00%	4.00%	4.00%	2.50%
TOTAL	-12.83%	-4.06%	2.00%	4.60%	4.93%
(Combined categories for graphing)					
Metals	-43.82%	-10.11%	-2.06%	-1.45%	1.44%
Min&For	-3.83%	0.00%	4.67%	4.67%	4.98%
Food&Oth	1.69%	1.48%	4.48%	4.48%	3.82%

ENERGY INTENSITY BY SE (TJ/E6K)

Mining	2.06	1.82	1.83	1.86	1.86	1.86
Chemical	19.36	15.11	16.48	17.05	17.05	17.05
Ferr.Met.	10.68	8.00	8.42	8.62	8.62	8.62
NF metal	8.18	6.22	6.73	6.97	6.97	6.97
Mech.En	2.95	2.57	2.62	2.66	2.66	2.66
Construc	1.36	1.18	1.25	1.27	1.27	1.27
Forest Pr	1.26	1.13	1.14	1.15	1.15	1.15
Food Ind.	1.66	1.43	1.48	1.50	1.50	1.50
Other	2.55	2.19	2.25	2.29	2.29	2.29
TOTAL	4.26	2.83	3.02	3.06	2.90	2.70
(Combined categories for graphing)						
Metals	10.06	7.55	7.97	8.17	8.15	8.16
Min&For	1.35	1.21	1.22	1.23	1.22	1.21
Food&O	2.12	1.83	1.88	1.91	1.91	1.87

PERCENTAGE PRICE INCREASES FOR FUELS

Electric	112.0%	8.0%	-4.8%	0.0%	0.0%
Thermal	112.0%	8.0%	-4.8%	0.0%	0.0%
Coal	70.0%	0.0%	0.0%	0.0%	0.0%
Petrol	53.0%	-2.6%	-4.7%	0.0%	0.0%
Nat.Gas	100.0%	-33.5%	-11.3%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%
Other	0.0%	0.0%	0.0%	0.0%	0.0%

PERCENTAGE SHARES OF INDUSTRIAL OUTPUT

Mining	2.50%	2.58%	2.69%	2.69%	2.56%	1.97%
Chemical	8.70%	5.75%	6.13%	5.99%	5.15%	4.22%
Ferr.Met.	7.40%	5.12%	4.72%	4.46%	3.91%	3.21%
NF metals	3.20%	1.71%	1.68%	1.69%	1.54%	1.25%
Mech.Eng.	12.90%	14.64%	14.95%	15.71%	17.38%	20.43%
Construc.	20.00%	18.35%	15.31%	13.50%	13.40%	14.16%
Forest Pr	18.50%	20.59%	21.46%	22.09%	22.26%	22.99%
Food Ind.	12.80%	14.98%	15.92%	16.39%	16.52%	16.77%
Other	14.00%	16.29%	17.14%	17.48%	17.28%	15.01%
(Combined categories for graphing)						
Metals	10.60%	6.83%	6.40%	6.15%	5.46%	4.45%
Min&For	21.00%	23.17%	24.15%	24.78%	24.82%	24.96%
Food&Oth	26.80%	31.26%	33.07%	33.87%	33.80%	31.78%

PERCENTAGE SHARES OF ENERGY USE

Mining	1.21%	1.66%	1.63%	1.63%	1.64%	1.36%
Chemical	39.59%	30.72%	33.45%	33.34%	30.26%	26.62%
Ferr.Met.	18.91%	14.46%	13.16%	12.55%	11.62%	10.23%
NF metals	6.15%	3.77%	3.75%	3.83%	3.70%	3.21%
Mech.Eng.	8.93%	13.29%	12.98%	13.62%	15.90%	20.07%
Construc.	6.37%	7.66%	6.34%	5.62%	5.88%	6.68%
Forest Pr	5.48%	8.25%	8.10%	8.29%	8.82%	9.78%
Food Ind.	4.98%	7.60%	7.80%	8.04%	8.55%	9.33%
Other	8.38%	12.59%	12.79%	13.07%	13.64%	12.72%
(Combined categories for graphing)						
Metals	25.06%	18.23%	16.91%	16.38%	15.32%	13.44%
Min&For	6.68%	9.91%	9.74%	9.92%	10.46%	11.14%
Food&Oth	13.36%	20.19%	20.59%	21.11%	22.19%	22.05%

GROSS INDUSTRIAL PRODUCT (Millions of Romanian Lei)

Mining	10460	9414	9414	9602	9990	10294
Chemical	36400	20971	21443	21381	20117	21997
Ferr.Met.	30962	18659	16513	15918	15288	16717
NF metals	13389	6255	5884	6016	6016	6501
Mech.Eng.	53974	53380	52313	56079	67856	106488
Construc.	83680	66944	53555	48200	52333	73817
Forest Pr	77404	75082	75082	78836	86917	119844
Food Ind.	53555	54626	55719	58505	64501	87430
Other	58576	59396	59990	62390	67481	78257
TOTAL	418400	364728	349912	356926	390499	521344
(Combined categories for graphing)						
Metals	44351	24914	22397	21934	21304	23217
Min&For	87864	84496	84496	88438	96907	130138
Food&Oth	112131	114022	115709	120894	131982	165687

******** ******** ********

* PRICING INPUT MODUL CASE TITLE: Scenario C (Low)

******** ******** ********

TARGET INCREASES IN ENERGY PRICES (in Romanian Lei):

	Electric (Lei/MW	Thermal (Lei/Gc)	Coal (Lei/Mt)	Petrol (Lei/Mt)	Nat.Gas (Lei/m3)	Solar (Lei/GJ)	Other (Lei/GJ)
1990	2.12	2.12	1.70	1.53	2.00	1.00	1.00
1991	2.29	2.29	1.70	1.49	1.33	1.00	1.00
1992	2.18	2.18	1.70	1.42	1.18	1.00	1.00
1994	2.18	2.18	1.70	1.42	1.18	1.00	1.00
2000	2.18	2.18	1.70	1.42	1.18	1.00	1.00

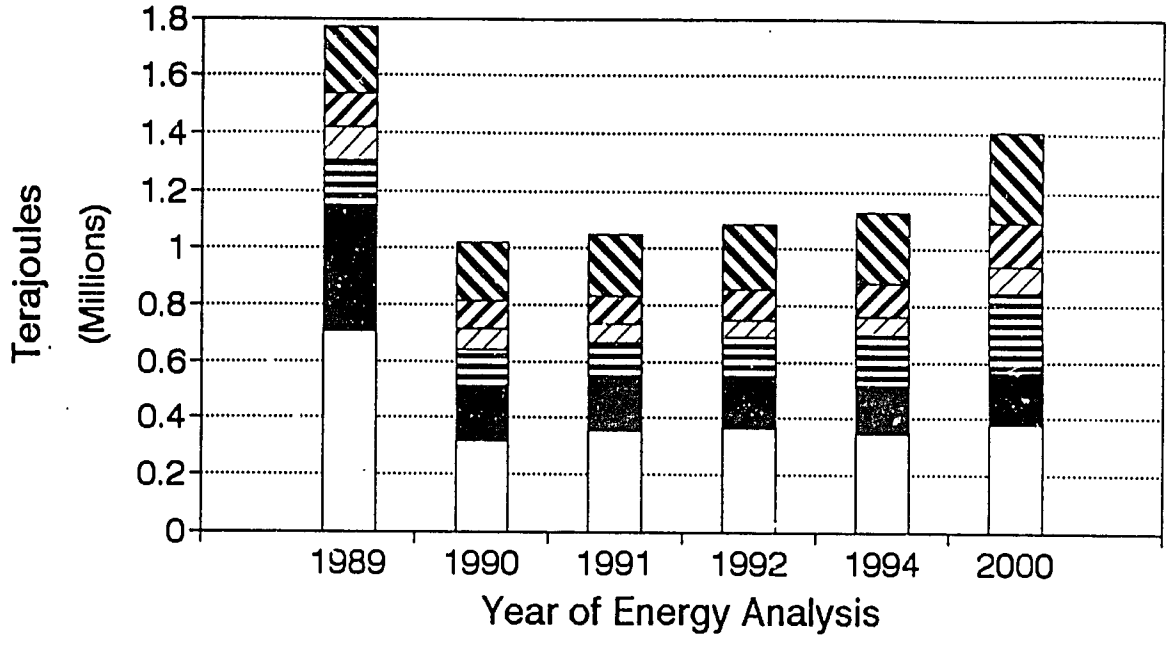
ENERGY PRICE RESPONSE FOR EACH SUBSECTOR AND FUEL TYPE:

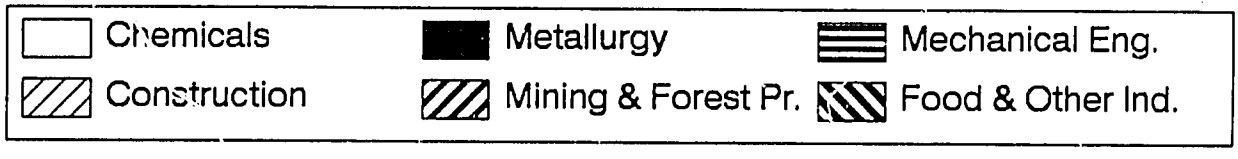
	Electric	Thermal	Coal	Petrol	Nat.Gas	Solar	Other
Mining	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Chemical	-0.35	-0.35	-0.35	-0.35	-0.35	0.00	0.00
Ferr.Met.	-0.50	-0.50	-0.50	-0.50	-0.50	0.00	0.00
NF metal	-0.40	-0.40	-0.40	-0.40	-0.40	0.00	0.00
Mech.En	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Construc.	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Forest Pr	-0.15	-0.15	-0.15	-0.15	-0.15	0.00	0.00
Food Ind.	-0.20	-0.20	-0.20	-0.20	-0.20	0.00	0.00
Other	-0.25	-0.25	-0.25	-0.25	-0.25	0.00	0.00

OUTPUT PRICE RESPONSE FOR EACH SUBSECTOR AND FUEL TYPE:

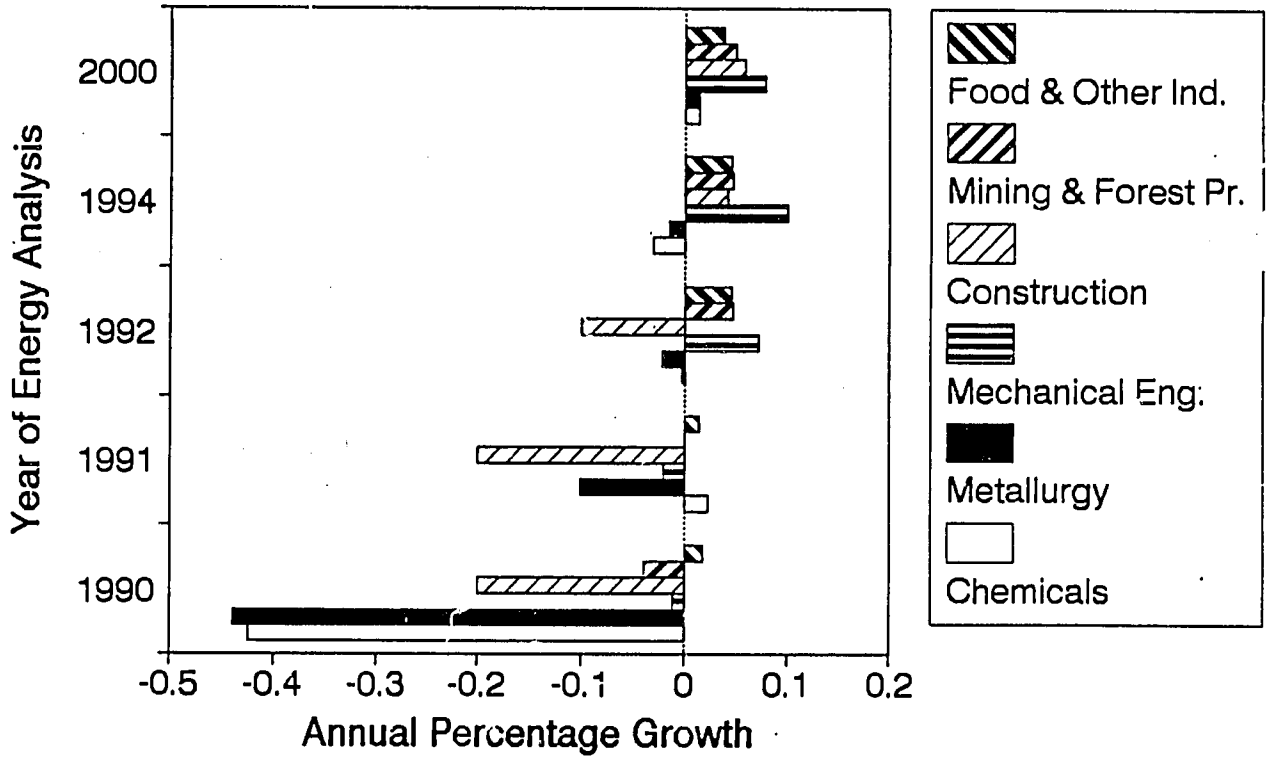
	Electric	Thermal	Coal	Petrol	Nat.Gas	Solar	Other
Mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chemical	-0.40	-0.40	0.00	-0.50	-0.50	0.00	0.00
Ferr.Met.	-0.40	-0.40	-0.30	-0.40	-0.40	0.00	0.00
NF metal	-0.50	-0.50	-0.30	-0.50	-0.50	0.00	0.00
Mech.En	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construc.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forest Pr	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food Ind.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Energy Consumption in Romanian Industry



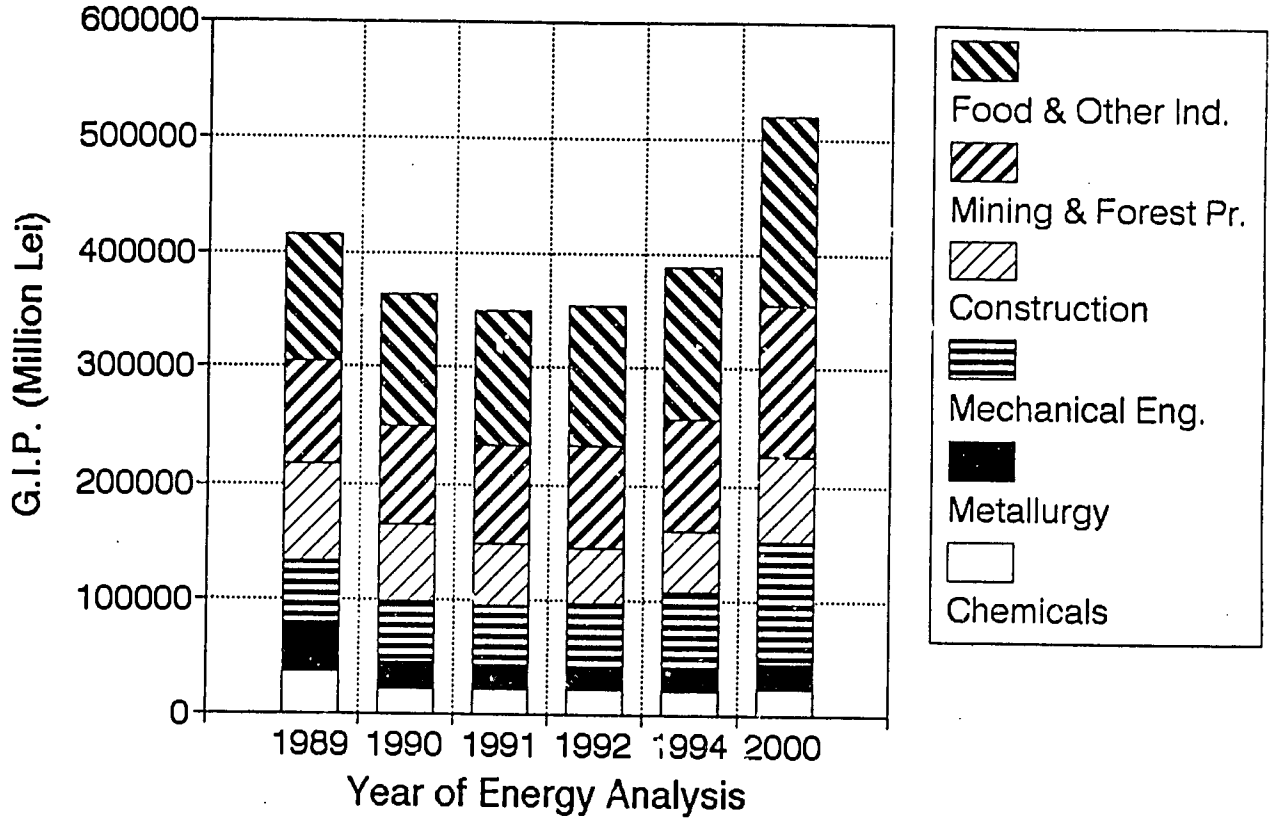


Growth Rates in Romanian Industry

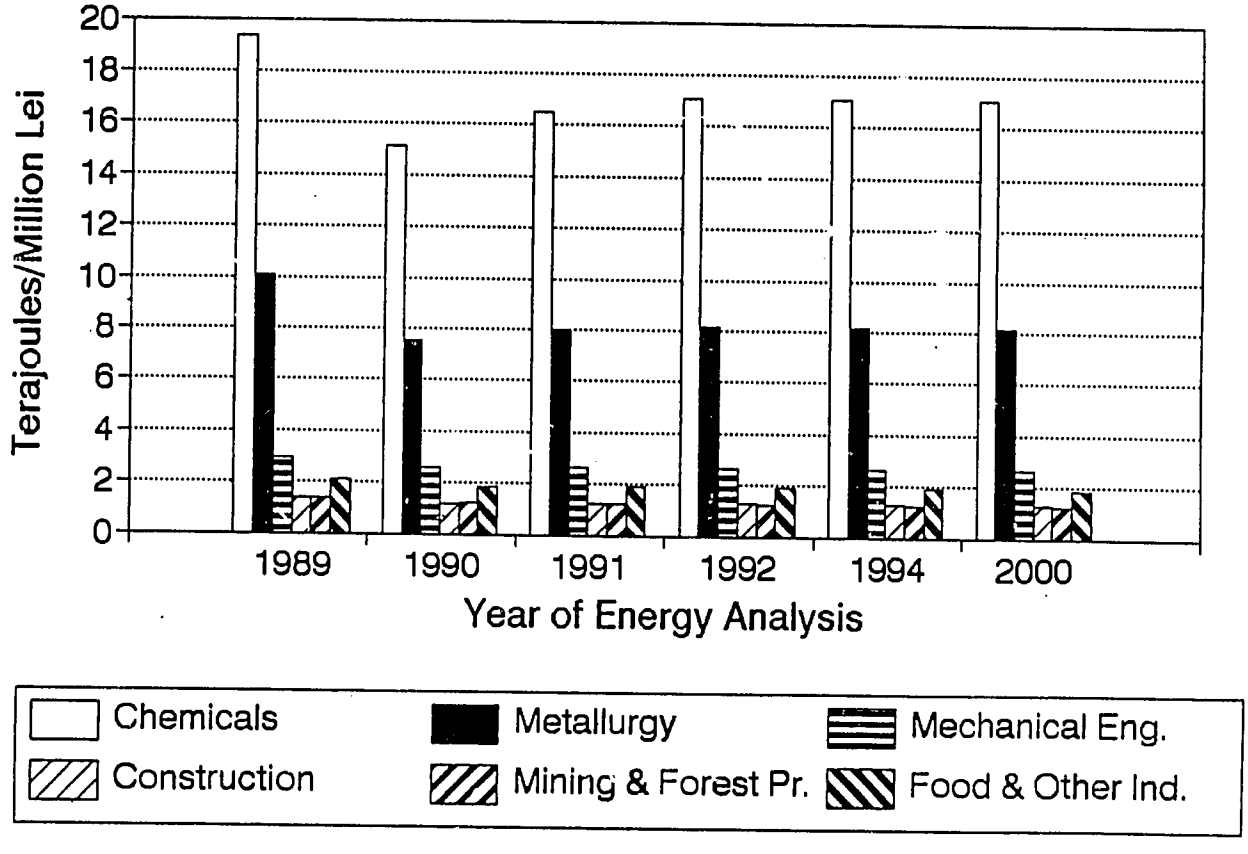


246

Gross Industrial Product in Romanian Industry



Energy Intensity in Romanian Industry



SCENARIO RESULTS FOR THE TRANSPORTATION MODEL

SCENARIOS FOR THE ROMANIAN TRANSPORTATION MODEL

FUEL PRICES (normalized to 1989 prices)

	Year	Diesel	Gasoline	Electricity
Scenario A Mid-price	1989	1	1	1
	1990	1.53	1.53	2.12
	1991	2.49	2.49	2.45
	1992	2.36	2.36	2.55
	2000	2.36	2.36	2.55
Scenario B High-price	1989	1	1	1
	1990	1.53	1.53	2.12
	1991	2.59	2.59	2.75
	1992	2.55	2.55	2.75
	2000	2.55	2.55	2.75
Scenario C Low-price	1989	1	1	1
	1990	1.53	1.53	2.12
	1991	1.49	1.49	2.29
	1992	1.42	1.42	2.18
	2000	1.42	1.42	2.18

GROSS DOMESTIC PRODUCT AND GDP OF INDUSTRY (Million Lei)

	Year	GDP	GDPi (used)	GDPi (calc)		Annual Growth Rate of GDPi
Scenario A	1989	793,700	418,400			
	1990	757,600	382,300	382292	1989-1990	-8.63%
	1991	741,981	366,681	366664	1990-1991	-4.09%
	1992	753,729	378,429	378415	1991-1992	3.20%
	1994	778,787	403,487	403505	1992-1994	3.26%
	2000	921,401	546,101	545985	1994-2000	5.17%
Scenario B	1989	793,700	418,400			
	1990	757,987	382,687	382292	1989-1990	-8.63%
	1991	740,884	365,584	365696	1990-1991	-4.44%
	1992	752,625	377,325	377392	1991-1992	3.23%
	1994	777,786	402,486	402412	1992-1994	3.27%
	2000	920,307	545,007	545042	1994-2000	5.18%
Scenario C	1989	793,700	418,400			
	1990	757,600	382,300	382292	1989-1990	-8.63%
	1991	745,427	370,127	370143	1990-1991	-3.18%
	1992	758,287	382,987	382970	1991-1992	3.47%
	1994	782,941	407,641	407653	1992-1994	3.17%
	2000	925,934	550,634	550663	1994-2000	5.14%

ELASTICITIES

GDP Elasticity (Egpd) of Passenger Trip Making

Egdp= 1.00

Gross Domestic Product of Industry Elasticity (Egdpi) of Shipping

Egdpi= 1.00

Fuel Price Elasticity (Ef) of Trip Making

E(gasoline)= -0.10
E(diesel)= -0.10
E(electricity)= -0.10

Fuel Price Elasticity (Ef) of Shipping

E(gasoline)= -0.10
E(diesel)= -0.10
E(electricity)= -0.10

Fuel Efficiency Elasticity (Ee) of Fuel Price
-passenger transportation

E(gasoline)= -0.20
E(diesel)= 0.00
E(electricity)= 0.00

Fuel Efficiency Elasticity (Ee) of Fuel Price
-freight

E(gasoline)= 0.00
E(diesel)= -0.20
E(electricity)= 0.00

Summary Table for Energy Use
Scenario A

FREIGHT and PASSENGER TRANSPORTATION

	Total Energy Use (1000 Gigajoules)		
	1989	1994	2000
- by Fuel			
-Gasoline	265,832	197,726	295,943
-Diesel	229,782	171,619	232,894
-Electricity	17,631	13,008	17,898
- by Mode			
Freight			
Train	15,021	10,940	14,803
Lg Truck	196,152	146,210	197,846
Sm Truck	27,875	20,778	28,116
Passenger			
TRAIN	1376	1,090	1,632
SUBWAY	907	719	1,076
TROLLEY	65	52	77
TRAM	261	207	310
BUS	5755	4,631	6,932
TAXI	24164	19,446	29,106
CAR	241669	178,280	266,838
TOTAL:	513,245	382,352	546,735
Energy Intensity			
-Passenger	1,816	1,417	1,417
-Freight	1631	1,373	1,373

Summary Table for Energy Use
Scenario B

FREIGHT and PASSENGER TRANSPORTATION

	Total Energy Use (1000 Gigajoules)		
	1989	1994	2000
- by Fuel			
-Gasoline	265,832	194,029	290,503
-Diesel	229,782	167,253	227,102
-Electricity	17,631	12,696	17,480
- by Mode			
Freight			
Train	15,021	10,666	14,440
Lg Truck	196,152	142,463	192,887
Sm Truck	27,875	20,245	27,411
Passenger			
TRAIN	1376	1,070	1,602
SUBWAY	907	706	1,057
TROLLEY	65	51	76
TRAM	261	203	304
BUS	5755	4,545	6,805
TAXI	24164	19,082	28,571
CAR	241669	174,946	261,932
TOTAL:	513,245	373,978	535,085
Energy Intensity			
-Passenger	1,816	1,395	1,395
-Freight	1631	1,352	1,352

Summary Table for Energy Use
Scenario C

FREIGHT and PASSENGER TRANSPORTATION

	Total Energy Use (1000 Gigajoules)		
	1989	1994	2000
- by Fuel			
-Gasoline	265,832	221,680	331,591
-Diesel	229,782	201,670	273,179
-Electricity	17,631	13,745	18,881
- by Mode			
Freight			
Train	15,021	11,584	15,649
Lg Truck	196,152	172,031	232,388
Sm Truck	27,875	24,447	33,024
Passenger			
TRAIN	1376	1,139	1,704
SUBWAY	907	751	1,124
TROLLEY	65	54	81
TRAM	261	216	324
BUS	5755	5,192	7,767
TAXI	24164	21,802	32,611
CAR	241669	199,878	298,980
TOTAL:	513,245	437,095	623,652
Energy Intensity			
-Passenger	1,816	1,568	1,568
-Freight	1631	1,519	1,519

Summary Table for Emission Load :
(Tonnes/Year) Scenario A

	1989	1994	2000
HC	953260	908139	1354290
-Gasoline	914289	873648	1307618
-Diesel	38971	34491	46672
-Electricity	0	0	0
CO	6295328	6007200	8976218
-Gasoline	6177625	5903028	8835256
-Diesel	117703	104172	140963
-Electricity	0	0	0
NOx	503090	456084	654917
-Gasoline	259460	247927	371081
-Diesel	220116	189812	256848
-Electricity	23514	18345	26988
SPM	435413	340974	508854
-Gasoline	345947	330570	494774
-Diesel	89466	10405	14080
-Electricity	na	na	na
SO2	196591	165442	243674
-Gasoline	61776	59030	88353
-Diesel	11756	10405	14080
-Electricity	123058	96006	141242
LEAD	4819	4604	6891
-Gasoline	4819	4604	6891
-Diesel	NA	NA	NA
-Electricity	0	0	0

Summary Table for Emission Load :
(Tonnes/Year) Scenario B

	1989	1994	2000
HC	953260	904824	1349826
-Gasoline	914289	870692	1303613
-Diesel	38971	34132	46213
-Electricity	0	0	0
CO	6295328	5986139	8947771
-Gasoline	6177625	5883052	8808197
-Diesel	117703	103087	139574
-Electricity	0	0	0
NOx	503090	452910	650735
-Gasoline	259460	247088	369944
-Diesel	220116	187835	254317
-Electricity	23514	17987	26474
SPM	435413	339747	507200
-Gasoline	345947	329451	493259
-Diesel	89466	10296	13941
-Electricity	na	na	na
SO2	196591	163259	240572
-Gasoline	61776	58831	88082
-Diesel	11756	10296	13941
-Electricity	123058	94132	138549
LEAD	4819	4589	6870
-Gasoline	4819	4589	6870
-Diesel	NA	NA	NA
-Electricity	0	0	0

Summary Table for Emission Load :
(Tonnes/Year) Scenario C

	1989	1994	2000
HC	953260	921520	1373107
-Gasoline	914289	884859	1323582
-Diesel	38971	36662	49525
-Electricity	0	0	0
CO	6295328	6089503	9092701
-Gasoline	6177625	5978775	8943124
-Diesel	117703	110728	149577
-Electricity	0	0	0
NOx	503090	472083	676399
-Gasoline	259460	251109	375611
-Diesel	220116	201757	272544
-Electricity	23514	19217	28244
SPM	435413	345871	515755
-Gasoline	345947	334811	500815
-Diesel	89466	11060	14940
-Electricity	na	na	na
SO2	196591	171419	252184
-Gasoline	61776	59788	89431
-Diesel	11756	11060	14940
-Electricity	123058	100572	147813
LEAD	4819	4663	6976
-Gasoline	4819	4663	6976
-Diesel	NA	NA	NA
-Electricity	0	0	0

SCENARIO RESULTS FOR THE LEAP MODEL

Energy Balance

Area: Romania Workshop
Year: 1989
Demand scenario: C2 - C revised 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	486.61	44.59			42.01	9.54			2039.18
EXPORTS			-78.40		-52.87										-131.27
IMPORTS	870.99	40.84		31.56		630.47	121.58		28.08						1723.52
TOTAL SUPPLY	1172.45	40.84	-78.40	31.56	-52.87	1785.42	608.19	44.59	28.08		42.01	9.54			3631.43
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.04							-0.04
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-207.95		-354.02				393.38					-168.59
ELECTRICITY				-129.98		-335.26	-316.29	-44.55	248.60	198.45	-42.01	-9.54			-430.57
DISTRIBUTION		-13.99	-12.09	-4.92		-42.12	-11.89		-17.71	-59.18					-161.91
FINAL CONSUMPTION		265.80	229.80	93.40		975.29	226.00		258.97	481.18					2530.45
INDUSTRY				93.40		847.00	226.00		179.00	436.00					1781.40
TRANSPORT		265.80	229.80						17.63						513.23
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		265.80	229.80	93.40		975.29	226.00		258.97	532.65					2581.91
SHORTFALL										51.47					

12:28:12 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1991
Demand scenario: C2 - C revised 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	345.54	29.35			27.65	6.28			1865.24
EXPORTS			-90.23	-100.70	-52.87										-243.80
IMPORTS	870.99	22.27				48.32	18.86		28.08						988.53
TOTAL SUPPLY	1172.45	22.27	-90.23	-100.70	-52.87	1203.28	364.40	29.35	28.08		27.65	6.28			2609.96
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-38.36								-38.36
CENTRAL THERMAL				-140.44		-239.09				265.67					-113.86
ELECTRICITY				-85.54		-220.64	-208.15	-29.32	163.61	130.61	-27.65	-6.28			-283.37
DISTRIBUTION		-13.06	-11.50	-3.90		-27.52	-5.89		-12.27	-39.63					-113.78
FINAL CONSUMPTION		248.16	218.56	74.10		637.29	112.00		179.42	305.18					1774.71
INDUSTRY				74.10		509.00	112.00		101.00	260.00					1056.10
TRANSPORT		248.16	218.56						16.08						482.80
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		248.16	218.56	74.10		637.29	112.00		179.42	356.65					1826.18
SHORTFALL										51.47					

12:28:15 on 08-12-1991

256

Energy Balance

Area: Romania Workshop
Year: 1992
Demand scenario: C2 - C revised 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	347.76	29.77			28.05	6.37			1868.37
EXPORTS			-96.14	-91.01	-52.87										-240.02
IMPORTS	870.99	12.99				81.73	18.86		28.08						1012.65
TOTAL SUPPLY	1172.45	12.99	-96.14	-91.01	-52.87	1236.68	366.62	29.77	28.08		28.05	6.37			2640.99
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-38.60								-38.60
CENTRAL THERMAL				-145.31		-247.38				274.89					-117.81
ELECTRICITY				-86.78		-223.84	-211.18	-29.74	165.99	132.50	-28.05	-6.37			-287.48
DISTRIBUTION		-12.60	-11.21	-4.08		-28.43	-5.84		-12.42	-40.74					-115.31
FINAL CONSUMPTION		239.34	212.94	77.50		658.29	111.00		181.65	315.18					1795.90
INDUSTRY				77.50		530.00	111.00		104.00	270.00					1092.50
TRANSPORT		239.34	212.94						15.30						467.58
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		239.34	212.94	77.50		658.29	111.00		181.65	366.65					1847.37
SHORTFALL										51.47					

12:28:18 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1994
Demand scenario: C2 - C revised 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	362.35	31.01			29.22	6.63			1885.63
EXPORTS			-100.50	-65.95	-51.64										-218.09
IMPORTS	843.62					109.72	18.86		28.08						1000.28
TOTAL SUPPLY	1145.08		-100.50	-65.95	-51.64	1264.68	381.22	31.01	28.08		29.22	6.63			2667.82
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1145.08	233.37	312.81	395.24	51.64	-30.65				-50.27					-232.94
LIGNITE							-40.22								-40.22
CENTRAL THERMAL				-151.22		-257.43				286.05					-122.59
ELECTRICITY				-90.39		-233.13	-219.94	-30.98	172.87	138.00	-29.22	-6.63			-299.41
DISTRIBUTION		-11.67	-10.62	-4.38		-28.82	-6.05		-12.86	-42.41					-116.81
FINAL CONSUMPTION		221.70	201.70	83.30		667.29	115.00		188.09	331.38					1808.47
INDUSTRY				83.30		539.00	115.00		112.00	285.00					1134.30
TRANSPORT		221.70	201.70						13.75						437.15
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		221.70	201.70	83.30		667.29	115.00		188.09	381.65					1858.73
SHORTFALL										50.27					

12:28:21 on 08-12-1991

28

Energy Balance

Area: Romania Workshop
Year: 2000
Demand scenario: C2 - C revised 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	450.26	38.32			36.10	8.20			1989.29
EXPORTS			-32.71	-5.55	-52.87										-91.13
IMPORTS	870.99	110.11				340.17	18.86		28.08						1368.21
TOTAL SUPPLY	1172.45	110.11	-32.71	-5.55	-52.87	1495.13	469.12	38.32	28.08		36.10	8.20			3266.36
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.04							-0.04
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-49.98								-49.98
CENTRAL THERMAL				-182.19		-310.16				344.65					-147.71
ELECTRICITY				-111.68		-288.07	-271.77	-38.28	213.61	170.52	-36.10	-8.20			-369.97
DISTRIBUTION		-17.45	-14.38	-5.26		-33.87	-7.37		-15.47	-51.52					-145.32
FINAL CONSUMPTION		331.60	273.20	100.00		784.29	140.00		226.22	412.18					2267.50
INDUSTRY				100.00		656.00	140.00		145.00	367.00					1408.00
TRANSPORT		331.60	273.20						18.88						623.68
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		331.60	273.20	100.00		784.29	140.00		226.22	463.65					2318.96
SHORTFALL										51.47					

12:28:24 on 08-12-1991

Total Energy Demands

Area: Romania Workshop
Demand scenario: C2 - C revised 8/2
Energy Units: MILLION GIGAJOULES

	1989	1991	1992	1994	2000
ELECTRICITY	258.97	179.42	181.65	188.09	226.22
NATURAL GAS	975.29	637.29	658.29	667.29	784.29
GASOLINE	265.80	248.16	239.34	221.70	331.60
DIESEL/GAS OIL	229.80	218.56	212.94	201.70	273.20
FUEL (BLACK) OIL	93.40	74.10	77.50	83.30	100.00
COAL LIGNITE	226.00	112.00	111.00	115.00	140.00
HEAT (DISTRICT)	532.65	356.65	366.65	381.65	463.65
Total	2581.91	1826.18	1847.37	1858.73	2318.96

10:56:18 on 08-12-1991

Area: Romania Workshop Scenario Labels: C2, BA 12/08/91 11:47

TOTAL ENERGY SYSTEM
ALL FUELS

	1989	1991	1992	1994	2000	
AIR EMISSIONS						
CARBON DIOXIDE						
TOTAL	74.32	51.12	52.35	54.21	65.16	(BILLION KILOGRAMS)
BIOGENIC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CARBON MONOXIDE						
TOTAL	14.68	11.56	11.68	11.85	13.55	(MILLION KILOGRAMS)
HYDROCARBONS						
TOTAL	13.25	12.16	11.92	11.41	15.84	(BILLION KILOGRAMS)
ALDEHYDES	217.50	154.45	155.44	161.96	201.25	(THOUSAND KILOGRAMS)
BENZENE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
TAR	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
VOLATILE HYDROC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
FORMALDEHYDE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ORGANIC ACIDS	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
METHANE	215.44	188.46	185.81	180.14	243.57	(MILLION KILOGRAMS)
HYDROGEN SULFIDE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
METALS						
LEAD	68.92	45.40	46.10	48.01	59.27	(THOUSAND KILOGRAMS)
ARSENIC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
BORON	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CADMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CHROMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
MERCURY	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NICKEL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ZINC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NITROGEN OXIDES						
TOTAL	148.82	107.40	109.16	112.15	132.25	(MILLION KILOGRAMS)
NITROUS OXIDE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
SULFUR OXIDES						
TOTAL	707.28	483.59	496.76	515.35	619.95	(MILLION KILOGRAMS)
SULFUR DIOXIDE	10.34	6.81	6.90	7.19	8.88	(KILOGRAMS)
TOXIC HYDROCARBONS						
POLYCYCLIC ORGA	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
PARTICULATES						
TOTAL	237.46	157.32	160.12	166.70	204.88	(MILLION KILOGRAMS)
SIZE LESS THAN	100.97	66.95	68.32	71.14	87.25	(MILLION KILOGRAMS)
FUGATIVE COAL D	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
CARBON-14	0.00	0.00	0.00	0.00	0.00	(CURIES)
IODINE-131 (ELE	0.00	0.00	0.00	0.00	0.00	(CURIES)
IODINE-131 (NON	0.00	0.00	0.00	0.00	0.00	(CURIES)
NOBLE GASES	0.00	0.00	0.00	0.00	0.00	(CURIES)
RADON	0.00	0.00	0.00	0.00	0.00	(CURIES)
TRITIUM	0.00	0.00	0.00	0.00	0.00	(CURIES)
AMMONIA						
TOTAL	24.98	24.98	24.98	24.39	24.98	(MILLION KILOGRAMS)
THERMAL EMISSIONS						
TOTAL	0.00	0.00	0.00	0.00	0.00	(GIGAJOULES)
WATER EFFLUENTS						
SOLIDS						
TOTAL	114.25	114.25	114.25	111.58	114.25	(MILLION KILOGRAMS)
SUSPENDED	2240.18	2240.18	2240.18	2187.88	2240.18	(THOUSAND KILOGRAMS)
DISSOLVED	112.42	112.42	112.42	109.81	112.42	(MILLION KILOGRAMS)
OXYGEN DEMAND						
BIOCHEMICAL	6412.30	6412.30	6412.30	6262.64	6412.30	(THOUSAND KILOGRAMS)
CHEMICAL	10.61	10.61	10.61	10.36	10.61	(MILLION KILOGRAMS)
SULFATES						
TOTAL	126.39	126.39	126.39	124.89	126.39	(THOUSAND KILOGRAMS)
METALS						
TOTAL	24.75	24.75	24.75	24.18	24.75	(THOUSAND KILOGRAMS)
CADMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CHROMIUM	81.83	81.83	81.83	81.83	81.83	(KILOGRAMS)
COPPER	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
IRON	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
MERCURY	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ZINC	81.83	81.83	81.83	81.83	81.83	(KILOGRAMS)
SALTS						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NITRATES						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ORGANIC CARBON						
TOTAL	4491.36	4491.36	4491.36	4386.51	4491.36	(THOUSAND KILOGRAMS)
OIL AND GREASE	703.15	703.15	703.15	687.46	703.15	(THOUSAND KILOGRAMS)
CHLORIDES						
TOTAL	26.96	26.96	26.96	26.33	26.96	(MILLION KILOGRAMS)
AMMONIA						
TOTAL	672.05	672.05	672.05	656.36	672.05	(THOUSAND KILOGRAMS)
PHOSPHATES						
TOTAL	3360.27	3360.27	3360.27	3281.82	3360.27	(KILOGRAMS)

CYANIDE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
TRITIUM	0.00	0.00	0.00	0.00	0.00	(CURIES)
ACTIVATION & FI	0.00	0.00	0.00	0.00	0.00	(CURIES)
SOLID WASTES						
MINING WASTE						
INERT	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
TOTAL						
TOTAL	5734.70	4072.03	4098.18	4270.16	5305.95	(MILLION KILOGRAMS)
ASH						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
SCRUBBER SLUDGE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
LOW-LEVEL (CURI	0.00	0.00	0.00	0.00	0.00	(CURIES)
LOW-LEVEL (VOLU	0.00	0.00	0.00	0.00	0.00	(LITERS)
OCC HEALTH, SAFETY						
DEATHS						
TOTAL	1.67	1.36	1.36	1.39	1.59	(DEATHS)
INJURIES						
TOTAL	270.22	209.57	210.53	216.80	254.55	(INJURIES)
WORK DAYS LOST						
TOTAL	10.16	10.16	10.16	10.16	10.16	(THOUSAND WORK DAYS LOST)

Energy Balance

Area: Romania Workshop
Year: 1989
Demand scenario: B2 - B REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.93	48[illegible].61	44.59			42.01	9.54			2039.18
EXPORTS			-78.40		-52.87										-131.27
IMPORTS	870.99	40.84		31.56		630.47	121.58		28.08						1723.52
TOTAL SUPPLY	1172.45	40.84	-78.40	31.56	-52.87	1785.42	608.19	44.59	28.08		42.01	9.54			3631.43
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.04							-0.04
REFINING	-1172.[illegible]5	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-207.95		-354.02				393.38					-168.59
ELECTRICITY				-129.98		-335.26	-316.29	-44.55	248.60	198.45	-42.01	-9.54			-430.57
DISTRIBUTION		-13.99	-12.09	-4.92		-42.12	-11.89		-17.71	-59.18					-161.91
FINAL CONSUMPTION		265.80	229.80	93.40		975.29	226.00		258.97	481.18					2530.45
INDUSTRY				93.40		847.00	226.00		79.00	436.00					1781.40
TRANSPORT		265.80	229.80						17.63						513.23
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		265.80	229.80	93.40		975.29	226.00		258.97	532.65					2581.91
SHORTFALL										51.47					

12:26:07 on 08-12-1991

263

Energy Balance

Area: Romania Workshop
Year: 1991
Demand scenario: 92 - B REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	478.65	37.38			35.22	8.00			2015.66
EXPORTS			-102.97	-27.80	-52.87										-183.65
IMPORTS	870.99	12.42				316.00	18.86		28.08						1246.35
TOTAL SUPPLY	1172.45	12.42	-102.97	-27.80	-52.87	1470.95	497.51	37.38	28.08		35.22	8.00			3078.36
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.04							-0.04
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-53.13								-53.13
CENTRAL THERMAL				-178.63		-304.09				337.91					-144.82
ELECTRICITY				-108.94		-281.01	-265.11	-37.34	208.37	166.34	-35.22	-8.00			-360.89
DISTRIBUTION		-12.57	-10.87	-4.47		-33.41	-8.96		-15.13	-50.42					-135.84
FINAL CONSUMPTION		238.79	206.45	84.84		773.70	170.31		221.32	402.35					2097.78
INDUSTRY				84.84		645.41	170.31		143.27	357.17					1401.02
TRANSPORT		238.79	206.45						15.70						460.95
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		238.79	206.45	84.84		773.70	170.31		221.32	453.82					2149.25
SHORTFALL										51.47					

12:26:10 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1992
Demand scenario: B2 - B REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	416.90	33.77			31.82	7.22			1946.12
EXPORTS			-112.85	-54.44	-52.48										-219.77
IMPORTS	862.17					158.53	18.86		28.08						1067.64
TOTAL SUPPLY	1163.63		-112.85	-54.44	-52.48	1313.48	435.76	33.77	28.08		31.82	7.22			2794.00
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1163.63	237.15	317.88	401.64	52.48	-31.15				-51.08					-236.71
LIGNITE							-46.28								-46.28
CENTRAL THERMAL				-163.97		-279.13				310.17					-132.93
ELECTRICITY				-98.43		-253.88	-239.51	-33.74	188.26	150.28	-31.82	-7.22			-326.06
DISTRIBUTION		-11.86	-10.25	-4.24		-29.06	-7.50		-13.85	-46.05					-122.80
FINAL CONSUMPTION		225.29	194.78	80.57		672.91	142.47		202.49	363.33					1881.84
INDUSTRY				80.57		544.62	142.47		125.41	317.76					1210.82
TRANSPORT		225.29	194.78						14.74						434.81
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		225.29	194.78	80.57		672.91	142.47		202.49	414.41					1932.92
SHORTFALL										51.08					

12:26:13 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1994
Demand scenario: B2 - B REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					988.46	293.39	26.55			25.02	5.68			1640.56
EXPORTS			-99.32	-65.66	-46.19										-211.17
IMPORTS	722.69						18.86		28.08						769.63
TOTAL SUPPLY	1024.15		-99.32	-65.66	-46.19	988.46	312.25	26.55	28.08		25.02	5.68			2199.02
NATURAL GAS						-40.53									-40.53
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1024.15	208.72	279.78	353.50	46.19	-27.41				-44.96					-208.34
LIGNITE							-32.57								-32.57
CENTRAL THERMAL				-134.64		-229.21				254.69					-109.15
ELECTRICITY				-77.40		-199.63	-188.33	-26.53	148.03	118.17	-25.02	-5.68			-256.38
DISTRIBUTION		-10.44	-9.02	-3.79		-20.36	-4.57		-11.27	-37.29					-96.73
FINAL CONSUMPTION		198.29	171.43	72.01		471.32	86.78		164.84	290.62					1455.30
INDUSTRY				72.01		343.04	86.78		89.68	238.93					830.44
TRANSPORT		198.29	171.43						12.82						382.53
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		198.29	171.43	72.01		471.32	86.78		164.84	335.58					1500.26
SHORTFALL										44.96					

12:26:16 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 2000
Demand scenario: B2 - B REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	370.21	32.99			31.09	7.06			1897.77
EXPORTS			-77.91	-54.69	-52.87										-185.47
IMPORTS	870.99	57.63				28.55	18.86		28.08						1004.11
TOTAL SUPPLY	1172.45	57.63	-77.91	-54.69	-52.87	1183.50	389.07	32.99	28.08		31.09	7.06			2716.40
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-41.09								-41.09
CENTRAL THERMAL				-162.00		-275.78				306.44					-131.33
ELECTRICITY				-96.17		-248.06	-234.03	-32.96	183.95	146.84	-31.09	-7.06			-318.59
DISTRIBUTION		-14.83	-12.12	-4.59		-24.05	-5.70		-13.57	-45.33					-120.18
FINAL CONSUMPTION		281.75	230.26	87.24		556.87	108.25		198.46	356.49					1819.31
INDUSTRY				87.24		428.58	108.25		118.68	311.30					1054.05
TRANSPORT		281.75	230.26						17.44						529.44
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		281.75	230.26	87.24		556.87	108.25		198.46	407.95					1870.78
SHORTFALL										51.47					

12:26:19 on 08-12-1991

267

Total Energy Demands

Area: Romania Workshop
Demand scenario: B2 - B REVISED 8/2
Energy Units: MILLION GIGAJOULES

	1989	1991	1992	1994	2000
ELECTRICITY	258.97	221.32	202.49	164.84	198.46
NATURAL GAS	975.29	773.70	672.91	471.32	556.87
GASOLINE	265.80	238.79	225.29	198.29	281.75
DIESEL/GAS OIL	229.80	206.45	194.78	171.43	230.26
FUEL (BLACK) OIL	93.40	84.84	80.57	72.01	87.24
COAL LIGNITE	226.00	170.31	142.47	86.78	108.25
HEAT (DISTRICT)	532.65	453.82	414.41	335.58	407.95
Total	2581.91	2149.25	1932.92	1500.26	1870.78

10:51:16 on 08-12-1991

Area: Romania Workshop Scenario Labels: B2, BA 12/08/91 11:38

TOTAL ENERGY SYSTEM
ALL FUELS

	1989	1991	1992	1994	2000	
AIR EMISSIONS						
CARBON DIOXIDE						
TOTAL	74.32	63.85	58.58	47.60	57.71	(BILLION KILOGRAMS)
BIOGENIC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CARBON MONOXIDE						
TOTAL	14.68	13.58	12.66	10.32	12.33	(MILLION KILOGRAMS)
HYDROCARBONS						
TOTAL	13.25	11.93	11.27	9.95	13.47	(BILLION KILOGRAMS)
ALDEHYDES	217.50	213.94	186.34	131.14	165.47	(THOUSAND KILOGRAMS)
BENZENE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
TAR	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
VOLATILE HYDROC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
FORMALDEHYDE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ORGANIC ACIDS	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
METHANE	215.44	194.68	181.29	154.25	205.24	(MILLION KILOGRAMS)
HYDROGEN SULFIDE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
METALS						
LEAD	68.92	57.82	52.28	41.18	51.10	(THOUSAND KILOGRAMS)
ARSENIC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
BORON	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CADMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CHROMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
MERCURY	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NICKEL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ZINC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NITROGEN OXIDES						
TOTAL	148.82	129.92	120.15	98.51	118.39	(MILLION KILOGRAMS)
NITROUS OXIDE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
SULFUR OXIDES						
TOTAL	707.28	607.62	557.50	454.62	549.62	(MILLION KILOGRAMS)
SULFUR DIOXIDE	10.34	8.67	7.83	6.16	7.65	(KILOGRAMS)
TOXIC HYDROCARBONS						
POLYCYCLIC ORGA	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
PARTICULATES						
TOTAL	237.46	200.11	181.35	143.84	177.50	(MILLION KILOGRAMS)
SIZE LESS THAN	100.97	85.24	77.37	61.64	75.85	(MILLION KILOGRAMS)
FUGATIVE COAL D	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
CARBON-14	0.00	0.00	0.00	0.00	0.00	(CURIES)
IODINE-131 (ELE	0.00	0.00	0.00	0.00	0.00	(CURIES)
IODINE-131 (NON	0.00	0.00	0.00	0.00	0.00	(CURIES)
NOBLE GASES	0.00	0.00	0.00	0.00	0.00	(CURIES)
RADON	0.00	0.00	0.00	0.00	0.00	(CURIES)
TRITIUM	0.00	0.00	0.00	0.00	0.00	(CURIES)
AMMONIA						
TOTAL	24.98	24.98	24.79	21.82	24.98	(MILLION KILOGRAMS)
THERMAL EMISSIONS						
TOTAL	0.00	0.00	0.00	0.00	0.00	(GIGAJOULES)
WATER EFFLUENTS						
SOLIDS						
TOTAL	114.25	114.25	113.39	99.80	114.25	(MILLION KILOGRAMS)
SUSPENDED	2240.18	2240.18	2223.33	1956.82	2240.18	(THOUSAND KILOGRAMS)
DISSOLVED	112.42	112.42	111.58	98.20	112.42	(MILLION KILOGRAMS)
OXYGEN DEMAND						
BIOCHEMICAL	6412.30	6412.30	6364.08	5601.20	6412.30	(THOUSAND KILOGRAMS)
CHEMICAL	10.61	10.61	10.53	9.26	10.61	(MILLION KILOGRAMS)
SULFATES						
TOTAL	126.39	126.39	125.91	109.30	126.39	(THOUSAND KILOGRAMS)
METALS						
TOTAL	24.75	24.75	24.57	21.62	24.75	(THOUSAND KILOGRAMS)
CADMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CHROMIUM	81.83	81.83	81.83	70.04	81.83	(KILOGRAMS)
COPPER	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
IRON	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
MERCURY	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ZINC	81.83	81.83	81.83	70.04	81.83	(KILOGRAMS)
SALTS						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NITRATES						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ORGANIC CARBON						
TOTAL	4491.36	4491.36	4457.58	3923.26	4491.36	(THOUSAND KILOGRAMS)
OIL AND GREASE	703.15	703.15	698.09	613.66	703.15	(THOUSAND KILOGRAMS)
CHLORIDES						
TOTAL	26.96	26.96	26.76	23.55	26.96	(MILLION KILOGRAMS)
AMMONIA						
TOTAL	672.05	672.05	667.00	587.05	672.05	(THOUSAND KILOGRAMS)
PHOSPHATES						
TOTAL	3360.27	3360.27	3334.99	2935.23	3360.27	(KILOGRAMS)

CYANIDE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
TRITIUM	0.00	0.00	0.00	0.00	0.00	(CURIES)
ACTIVATION ! FI	0.00	0.00	0.00	0.00	0.00	(CURIES)
SOLID WASTES						
MINING WASTE						
INERT	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
TOTAL						
TOTAL	5734.70	5640.22	4912.69	3457.62	4362.88	(MILLION KILOGRAMS)
ASH						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
SCRUBBER SLUDGE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
LOW-LEVEL (CURI	0.00	0.00	0.00	0.00	0.00	(CURIES)
LOW-LEVEL (VOLU	0.00	0.00	0.00	0.00	0.00	(LITERS)
CCC HEALTH, SAFETY						
DEATHS						
TOTAL	1.67	1.65	1.51	1.24	1.41	(DEATHS)
INJURIES						
TOTAL	270.22	266.70	240.20	187.20	220.19	(INJURIES)
WORK DAYS LOST						
TOTAL	10.16	10.16	10.16	10.16	10.16	(THOUSAND WORK DAYS LOST)

Energy Balance

Area: Romania Workshop
Year: 1989
Demand scenario: A2 - A REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	486.61	44.59			42.01	9.54			2039.16
EXPORTS		-27.37	-78.19		-52.87										-158.43
IMPORTS	870.99			35.67		630.45	293.12		28.08						1858.30
TOTAL SUPPLY	1172.45	-27.37	-78.19	35.67	-52.87	1785.40	779.73	44.59	28.08		42.01	9.54			3739.04
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.04							-0.04
REFINING	-1172.45	238.95	320.29	404.68	52.87	-31.38				-51.47					-238.51
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-207.97		-354.04				393.41					-168.60
ELECTRICITY				-129.96		-335.21	-316.25	-44.54	248.57	198.43	-42.01	-9.54			-430.51
DISTRIBUTION		-10.58	-12.11	-5.12		-42.12	-20.47		-17.71	-59.18					-167.29
FINAL CONSUMPTION		201.00	230.00	97.30		975.29	389.00		258.94	481.18					2632.72
INDUSTRY				97.30		847.00	389.00		179.00	436.00					1948.30
TRANSPORT		201.00	230.00						17.60						448.60
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		201.00	230.00	97.30		975.29	389.00		258.94	532.65					2684.18
SHORTFALL										51.47					

12:23:29 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1991
Demand scenario: A2 - A REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	486.61	36.02			33.94	7.71			2020.70
EXPORTS		-40.85	-117.43		-50.52										-208.81
IMPORTS	818.80					337.57	112.39		28.08						1296.84
TOTAL SUPPLY	1120.27	-40.85	-117.43		-50.52	1492.52	599.00	36.02	28.08		33.94	7.71			3108.73
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1120.27	228.31	306.03	386.67	50.52	-29.99				-49.18					-227.89
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-182.54		-310.74				345.30					-147.98
ELECTRICITY				-104.99		-270.81	-255.49	-35.99	200.81	160.31	-33.94	-7.71			-347.80
DISTRIBUTION		-9.37	-9.43	-4.96		-34.51	-14.47		-14.65	-50.56					-137.96
FINAL CONSUMPTION		178.09	179.17	94.19		799.11	275.02		214.25	405.87					2145.69
INDUSTRY				94.19		670.82	275.02		140.52	358.39					1538.94
TRANSPORT		178.09	179.17						11.39						368.64
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		178.09	179.17	94.19		799.11	275.02		214.25	455.04					2194.87
SHORTFALL										49.18					

12:23:32 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1992
Demand scenario: A2 - A REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	486.61	35.72			33.66	7.64			2020.05
EXPORTS		-69.20	-176.60		-51.45										-297.26
IMPORTS	839.54					330.35	95.94		28.08						1293.90
TOTAL SUPPLY	1141.00	-69.20	-176.60		-51.45	1485.30	582.55	35.72	28.08		33.66	7.64			3016.70
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1141.00	232.54	311.70	393.83	51.45	-30.54				-50.09					-232.11
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-187.59		-319.35				354.86					-152.08
ELECTRICITY				-104.12		-268.57	-253.37	-35.69	199.15	158.98	-33.66	-7.64			-344.92
DISTRIBUTION		-8.17	-6.75	-5.11		-33.93	-13.76		-14.54	-51.38					-133.64
FINAL CONSUMPTION		155.17	128.34	97.01		785.56	261.41		212.69	412.37					2052.54
INDUSTRY				97.01		657.27	261.41		145.17	365.80					1526.66
TRANSPORT		155.17	128.34						[illegible].17						288.69
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		155.17	128.34	97.01		785.56	261.41		212.69	462.45					2102.63
SHORTFALL										50.09					

12:23:35 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 1994
Demand scenario: A2 - A REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	486.61	35.72			33.66	7.64			2020.05
EXPORTS		-69.20	-176.60		-51.45										-297.26
IMPORTS	839.54					330.35	95.94		28.08						1293.90
TOTAL SUPPLY	1141.00	-69.20	-176.60		-51.45	1485.30	582.55	35.72	28.08		33.66	7.64			3016.70
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1141.00	232.54	311.70	393.83	51.45	-30.54				-50.09					-232.11
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-187.59		-319.35				354.86					-152.08
ELECTRICITY				-104.12		-268.57	-253.37	-35.69	199.15	158.98	-33.66	-7.64			-344.92
DISTRIBUTION		-8.17	-6.75	-5.11		-33.93	-13.76		-14.54	-51.38					-133.64
FINAL CONSUMPTION		155.17	128.34	97.01		785.56	261.41		212.69	412.37					2052.54
INDUSTRY				97.01		657.27	261.41		145.17	365.80					1526.66
TRANSPORT		155.17	128.34						5.17						288.69
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		155.17	128.34	97.01		785.56	261.41		212.69	462.45					2102.63
SHORTFALL										50.09					

12:23:38 on 08-12-1991

Energy Balance

Area: Romania Workshop
Year: 2000
Demand scenario: A2 - A REVISED 8/2
Transformation scenario: BA - BASE CASE
Energy Units: MILLION GIGAJOULES

	CRUDE OIL	GASO-LINE	DIESEL	BLACK OIL	PETRO PRODS	NATURAL GAS	LIGNITE	ANTHRA-CITE	ELECT-RICITY	DISTRICT HEAT	HYDRO	RESIDUAL GAS	COGEN HEAT	OTHER	TOTAL
INDIGENOUS	301.46					1154.95	486.61	35.72			33.66	7.64			2020.05
EXPORTS		-69.20	-176.60		-51.45										-297.26
IMPORTS	839.54					330.35	95.94		28.08						1293.90
TOTAL SUPPLY	1141.00	-69.20	-176.60		-51.45	1485.30	582.55	35.72	28.08		33.66	7.64			3016.70
NATURAL GAS						-47.35									-47.35
CRUDE OIL															
ANTHRACITE								-0.03							-0.03
REFINING	-1141.00	232.54	311.70	393.83	51.45	-30.54				-50.09					-232.11
LIGNITE							-54.01								-54.01
CENTRAL THERMAL				-187.59		-319.35				354.86					-152.08
ELECTRICITY				-104.12		-268.57	-253.37	-35.69	199.15	158.98	-33.66	-7.64			-344.92
DISTRIBUTION		-8.17	-6.75	-5.11		-33.93	-13.76		-14.54	-51.38					-133.64
FINAL CONSUMPTION		155.17	128.34	97.01		785.56	261.41		212.69	412.37					2052.54
INDUSTRY				97.01		657.27	261.41		145.17	365.80					1526.66
TRANSPORT		155.17	128.34						5.17						288.69
SERVICE						23.13			21.32						44.45
DOMESTIC						105.16			15.47	96.65					217.28
PUBLIC SERVICES									10.55						10.55
AGRICULTURE									15.01						15.01
TOTAL		155.17	128.34	97.01		785.56	261.41		212.69	462.45					2102.63
SHORTFALL										50.09					

12:23:41 on 08-12-1991

Total Energy Demands

Area: Romania Workshop
Demand scenario: A2 - A REVISED 8/2
Energy Units: MILLION GIGAJOULES

	1989	1991	1992	1994	2000
ELECTRICITY	258.97	171.32	170.20	175.34	212.24
NATURAL GAS	975.29	517.29	508.29	520.29	614.29
GASOLINE	265.80	238.56	224.94	197.70	295.90
DIESEL/GAS OIL	229.80	206.52	194.88	171.60	232.90
FUEL (BLACK) OIL	93.40	72.30	76.30	82.10	99.10
COAL LIGNITE	226.00	107.00	106.00	109.00	134.00
HEAT (DISTRICT)	532.65	330.65	329.65	344.65	417.65
Total	2581.91	1643.64	1610.26	1600.68	2006.08

10:47:58 on 08-12-1991

Area: Romania Workshop Scenario Labels: A2, 8A 12/08/91 11:21

TOTAL ENERGY SYSTEM
ALL FUELS

	1989	1991	1992	1994	2000	
AIR EMISSIONS						
CARBON DIOXIDE						
TOTAL	74.32	47.84	47.65	49.05	59.37	(BILLION KILOGRAMS)
BIOGENIC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CARBON MONOXIDE						
TOTAL	14.68	11.14	11.06	10.73	12.85	(MILLION KILOGRAMS)
HYDROCARBONS						
TOTAL	13.25	11.64	11.17	10.17	14.12	(BILLION KILOGRAMS)
ALDEHYDES	217.50	146.26	144.97	150.07	188.52	(THOUSAND KILOGRAMS)
BENZENE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
TAR	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
VOLATILE HYDROC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
FORMALDEHYDE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ORGANIC ACIDS	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
METHANE	215.44	178.77	172.40	160.15	217.18	(MILLION KILOGRAMS)
HYDROGEN SULFIDE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
METALS						
LEAD	68.92	42.95	42.63	44.18	55.02	(THOUSAND KILOGRAMS)
ARSENIC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
BORON	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CADMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CHROMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
MERCURY	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NICKEL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ZINC	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NITROGEN OXIDES						
TOTAL	148.82	102.20	101.60	102.30	123.15	(MILLION KILOGRAMS)
NITROUS OXIDE	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
SULFUR OXIDES						
TOTAL	707.28	449.68	440.31	464.93	560.10	(MILLION KILOGRAMS)
SULFUR DIOXIDE	10.34	6.45	6.40	6.62	8.26	(KILOGRAMS)
TOXIC HYDROCARBONS						
POLYCYCLIC ORGA	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
PARTICULATES						
TOTAL	237.46	148.25	147.28	152.87	189.11	(MILLION KILOGRAMS)
SIZE LESS THAN	100.97	62.82	62.46	64.96	80.03	(MILLION KILOGRAMS)
FUGATIVE COAL D	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
CARBON-14	0.00	0.00	0.00	0.00	0.00	(CURIES)
IODINE-131 (ELE	0.00	0.00	0.00	0.00	0.00	(CURIES)
IODINE-131 (NON	0.00	0.00	0.00	0.00	0.00	(CURIES)
NOBLE GASES	0.00	0.00	0.00	0.00	0.00	(CURIES)
RADON	0.00	0.00	0.00	0.00	0.00	(CURIES)
TRITIUM	0.00	0.00	0.00	0.00	0.00	(CURIES)
AMMONIA						
TOTAL	24.98	24.98	24.75	21.75	24.98	(MILLION KILOGRAMS)
THERMAL EMISSIONS						
TOTAL	0.00	0.00	0.00	0.00	0.00	(GIGAJOULES)
WATER EFFLUENTS						
SOLIDS						
TOTAL	114.25	114.25	113.21	99.50	114.25	(MILLION KILOGRAMS)
SUSPENDED	2240.18	2240.18	2219.85	1951.03	2240.18	(THOUSAND KILOGRAMS)
DISSOLVED	112.42	112.38	111.36	97.93	112.42	(MILLION KILOGRAMS)
OXYGEN DEMAND						
BIOCHEMICAL	6412.30	6412.15	6353.97	5584.72	6412.30	(THOUSAND KILOGRAMS)
CHEMICAL	10.61	10.60	10.51	9.24	10.61	(MILLION KILOGRAMS)
SULFATES						
TOTAL	126.39	120.30	119.08	112.91	126.39	(THOUSAND KILOGRAMS)
METALS						
TOTAL	24.75	24.74	24.52	21.56	24.75	(THOUSAND KILOGRAMS)
CADMIUM	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
CHROMIUM	81.83	73.83	72.98	75.00	81.83	(KILOGRAMS)
COPPER	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
IRON	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
MERCURY	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ZINC	81.83	73.83	72.98	75.00	81.83	(KILOGRAMS)
SALTS						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
NITRATES						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
ORGANIC CARBON						
TOTAL	4491.36	4491.36	4450.61	3911.65	4491.36	(THOUSAND KILOGRAMS)
OIL AND GREASE	703.15	700.11	693.69	613.81	703.15	(THOUSAND KILOGRAMS)
CHLORIDES						
TOTAL	26.96	26.95	26.71	23.48	26.96	(MILLION KILOGRAMS)
AMMONIA						
TOTAL	672.05	672.05	665.96	585.31	672.05	(THOUSAND KILOGRAMS)
PHOSPHATES						
TOTAL	3360.27	3360.27	3329.78	2926.55	3360	

.27 (KILOGRAMS)						
CYANIDE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
TRITIUM	0.00	0.00	0.00	0.00	0.00	(CURIES)
ACTIVATION & FI	0.00	0.00	0.00	0.00	0.00	(CURIES)
SOLID WASTES						
MINING WASTE						
INERT	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
TOTAL						
TOTAL	5734.70	3856.32	3822.08	3956.70	4970.33	(MILLION KILOGRAMS)
ASH						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
SCRUBBER SLUDGE						
TOTAL	0.00	0.00	0.00	0.00	0.00	(KILOGRAMS)
RADIOACTIVE						
LOW-LEVEL (CURI	0.00	0.00	0.00	0.00	0.00	(CURIES)
LOW-LEVEL (VOLU	0.00	0.00	0.00	0.00	0.00	(LITERS)
OCC HEALTH, SAFETY						
DEATHS						
TOTAL	1.67	1.32	1.31	1.34	1.52	(DEATHS)
INJURIES						
TOTAL	270.22	201.71	200.46	205.37	242.32	(INJURIES)
WORK DAYS LOST						
TOTAL	10.16	10.16	10.16	10.16	10.16	(THOUSAND WORK DAYS LOST)

LEAP: POSSIBLE TRANSFORMATION MODULE LINKS WITH EDB

(For all modules except electricity)

PROCESS TYPE	PROCESS	TECHNOLOGY
FUEL DISTRIBUTION LOSSES	COAL	GENERIC
	NATURAL GAS	GENERIC
	ALL PETROLEUM PRODUTS	GENERIC
	OIL SPILLS	SPILLS FROM OCEAN TRANSPORTATION
REFINERY	STANDARD	GENERIC
CRUDE OIL PRODUCTION	ONSHORE	ENHANCED OIL * STEAM INJECTION * US MAINLAND PRIMARY OIL * US MAINLAND
	OFFSHORE	US MAINLAND
	SHALE OIL PRODUCTION	OIL SHALE MINING - SURFACE OIL SHALE MINING - UNDERGROUND SURFACE RETORTING * EC MODIFIED IN SITU RETORTING * EC
NATURAL GAS PRODUCTION	OFFSHORE	US MAINLAND
	ONSHORE	US MAINLAND
	PURIFICATION	DEHYDRATION/DESULF/CO2 REMOVAL/NG LIQ SEPARATION

219

PROCESS TYPE	PROCESS	TECHNOLOGY
COAL PRODUCTION	SURFACE MINES	EASTERN US TYPE * w/COAL PREP PLANT
		WESTERN US TYPE * w/COAL PREP PLANT
	UNDERGROUND MINES	EASTERN US TYPE * w/COAL PREP PLANT
	GASIFICATION	GENERIC - LOW BTU
		GENERIC - HIGH BTU
	LIQUFICATION	GENERIC

CHEMICAL COMPOSITION OF FUELS - ROMANIA
Dry Basis, By Weight

RESOURCE CATEGORIES	% CARBON	% SULFUR	% NITROGEN	% ASH
NATURAL GAS	75.0	0.0	0.0	0.0
GASOLINE	84.0	0.0	1.0	0.0
DIESEL/GAS OIL	82.0	0.4	0.6	0.0
RESIDUAL FUEL OIL	82.6	4.8	1.0	0.1
ALL PETROLEUM PRODUCTS	83.0	1.0	1.0	0.1
PETROCHEMICALS	0.0	0.0	0.0	0.0
CRUDE OIL	83.0	1.0	1.0	0.1
COAL BITUMINOUS	82.1	2.0	1.5	8.0
COAL ANTHRACITE	90.0	0.8	0.7	6.0
COAL LIGNITE	42.2	0.5	0.6	6.0

CURRENT TELLUS TRANSFORMATION MODULE LINKDS WITH EDB - ROMANIA

(For electricity module only)

MODULE/PROCESS	PROCESS TYPE	PROCESS	TECHNOLOGY
ELECTRICITY			
ROVINARI	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
TURCENI	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
MINTIA	ELECTRICITY GENERATION	STEAM-BITUMINOUS COAL	SPREADER-STOKER BOILER * NO EC
ISALNITA	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
DOICESTI	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
PAROSENI	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
ORADEA 1	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
GIURGIU	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
BORZESTI 2	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
DROBETA	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
IASI 2	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
CRAIOVA 2	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
ORADEA 2	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
SUCEAVA	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
BUCURESTI SUD	ELECTRICITY GENERATION	STEAM-RESIDUAL OIL	GENERIC BOILER * GRADE 6 OIL * NO EC

Note: "No EC" signifies that the technology has no emission controls.

282

MODULE/PROCESS		PROCESS	TECHNOLOGY
ELECTRICITY			
BUCURESTI VEST	ELECTRICITY GENERATION	STEAM NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
PROGRESUL	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
GROZAVESTI	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
BORZESTI	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
BRAZI	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
IASI 2	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
NAVODARI	ELECTRICITY GENERATION	STEAM-RESIDUAL OIL	GENERIC BOILER * GRADE 6 OIL * NO EC
PALAS	ELECTRICITY GENERATION	STEAM-RESIDUAL OIL	GENERIC BOILER * GRADE 6 OIL * NO EC
GALATI	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
BRAILA	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
PITESTI SUD	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
IERNUT	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
FINTINELE	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
GOVORA	ELECTRICITY GENERATION	STEAM-LIGNITE COAL	PULVERIZED LIGNITE * NO EC
ALL HYDRO	ELECTRICITY GENERATION	NO EDB LINK	
MISC SMALL	ELECTRICITY GENERATION	STEAM-NATURAL GAS	SMALL BOILER * < 100 GJ/HR (100 MMBTU/HR) * NO EC

282

CURRENT TELLUS TRANSFORMATION MODULE LINKS WITH EDB - ROMANIA

(For all modules except electricity)

MODULE/PROCESS	PROCESS TYPE	PROCESS	TECHNOLOGY
DISTRIBUTION			
ELECTRICITY	No Link with EDB		
RESIDUAL FUEL OIL	FUEL DISTRIBUTION LOSSES	ALL PETROLEUM PRODUCTS	GENERIC
PETROCHEMICALS	FUEL DISTRIBUTION LOSSES	ALL PETROLEUM PRODUCTS	GENERIC
NATURAL GAS	FUEL DISTRIBUTION LOSSES	NATURAL GAS	GENERIC
GASOLINE	FUEL DISTRIBUTION LOSSES	ALL PETROLEM PRODUCTS	GENERIC
DIESEL/GAS OIL	FUEL DISTRIBUTION LOSSES	ALL PETROLEM PRODUCTS	GENERIC
DISTRICT HEAT	No Link with EDB		
COAL LIGNITE	FUEL DISTRIBUTION LOSSES	COAL	GENERIC
COAL/ANTHRACITE	FUEL DISTRIBUTION LOSSES	COAL	GENERIC
CENTRAL THERMAL	No Link with EDB		
CENTRAL THERMAL			
NATURAL GAS THERMAL	ELECTRICITY GENERATION	STEAM-NATURAL GAS	LARGE BOILER
OIL THERMAL	ELECTRICITY GENERATION	STEAM-RESIDUAL	GENERIC UTILITY BOILER * GRADE 6 OIL
LIGNITE	COAL PRODUCTION	SURFACE MINES	EASTERN TYPE * COAL PREP PLANT
REFINING	REFINERY	STANDARD	GENERIC
ANTHRACITE	COAL PRODUCTION	SURFACE MINES	EASTERN TYPE * COAL PREP PLANT
CRUDE OIL	CRUDE OIL PRODUCTION	ONSHORE	U.S. MAINLAND/PRIMARY OIL
NATURAL GAS	NATURAL GAS PRODUCTION	ONSHORE	U.S. MAINLAND

LEAP: POSSIBLE TRANSFORMATION MODULE LINKS WITH EDB

(For electricity generation only)

PROCESS TYPE	PROCESS	TECHNOLOGY
ELECTRICITY GENERATION	COMBINED CYCLE-COAL	FLUIDIZED BED
		FLUIDIZED BED * SELECTIVE CATALYTIC REDUCTION
	COMBINED CYCLE-NATURAL GAS	SELECTIVE CATALYTIC REDUCTION
		GENERIC
	ENGINE-DIESEL	GENERIC
	ENGINE-KEROSENE	GENERIC * NO EC
	ENGINE-NATURAL GAS	GENERIC
	STEAM-ANTHRACITE COAL	PULVERIZED ANTHRACITE * NO EC
		TRAVELING GRATE (OVERFEED) STOKER * NO EC
	STEAM-BAGASSE	GENERIC * NO EC
	STEAM-BITUMINOUS COAL	ATMOSPHERIC FLUIDIZED BED * NO EC
		FLUIDIZED BED BOILER
		CYCLONE FURNACE * PULVERIZED BITUMINOUS COAL * NO EC
		US * ELECTROSTATIC PRECIPITATOR AND SOX SCRUBBER
		CYCLONE BOILER * PULVERIZED BITUMINOUS COAL
		DRY-BOTTOM BOILER * PULVERIZED BITUMINOUS COAL* NO EC
		DRY-BOTTOM TANGENTIALLY FIRED BOILER * PULVERIZED BITUMINOUS COAL
		WALL-FIRED BOILER * PULVERIZED BITUMINOUS COAL * NO EC
		WALL-FIRED BOILER * PULVERIZED BITUMINOUS COAL * LOW NOX BURNER
		TANGENTIALLY FIRED * PULVERIZED BITUMINOUS COAL
		WET-BOTTOM BOILER * PULVERIZED BITUMINOUS COAL * NO EC
		SPREADER-STOKER BOILER
		SPREADER-STOKER BOILER * NO EC
		TRAVELING GRATE (OVERFEED) STOKER BOILER * NO EC

Note: "No EC" signifies that the technology has no emission controls.

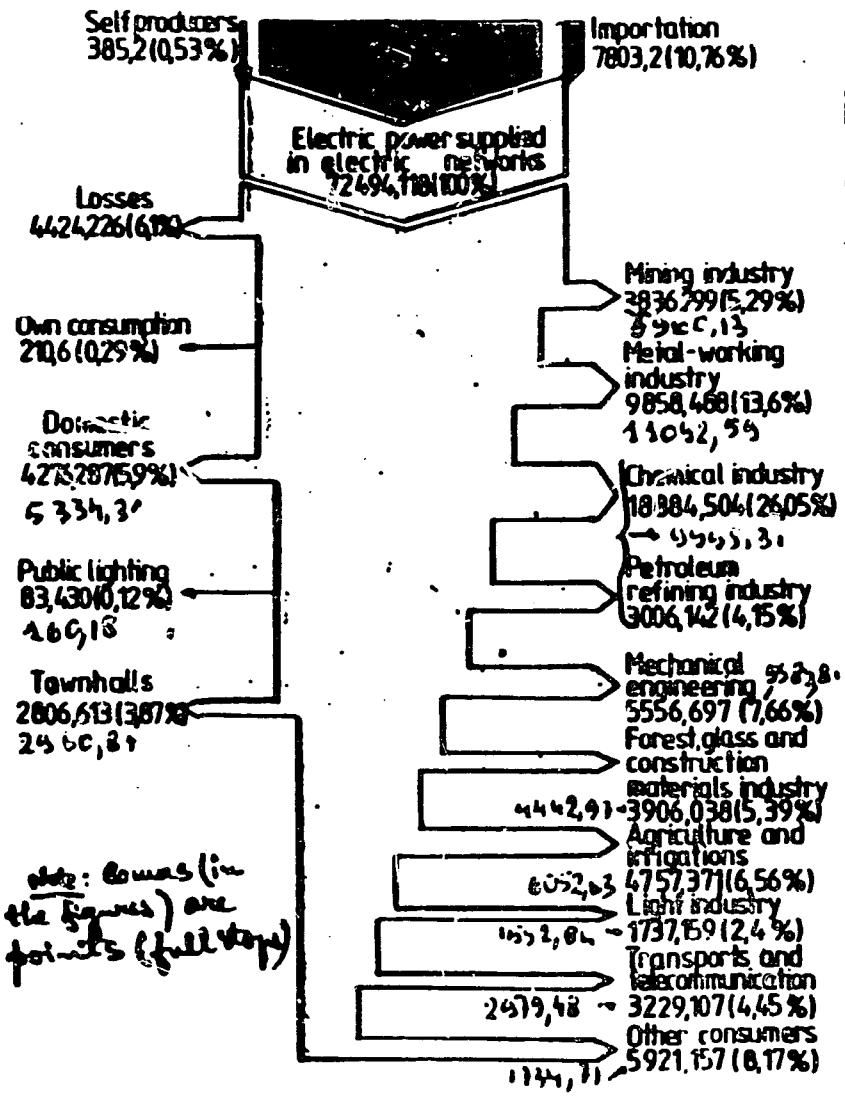
PROCESS TYPE	PROCESS	TECHNOLOGY
ELECTRICITY GENERATION (continued)	STEAM-COKE	GENERIC BOILER * NO EC
	STEAM-DIESEL	GENERIC UTILITY BOILER
		UTILITY BOILER * LOW NOX BURNER
		UTILITY BOILER * SELECTIVE CATALYTIC REDUCTION
		GENERIC * GRADE 1 AND 2 OIL * NO EC
		GENERIC * GRADE 4 OIL * NO EC
		GRADE 6 OIL * ELECTROSTATIC PRECIPITATOR AND SCRUBBER
		TANGENTIALLY FIRED BOILER * GRADE 4 OIL * NO EC
	STEAM-GEOTHERMAL	VAPOR DOMINATED SYSTEM (dry steam)
		HYDROTHERMAL FLASHED STEAM
	STEAM-LIGNITE COAL	CYCLONE FURNACE - NO EC
		TANGENTIALLY FIRED BOILER * PULVERIZED LIGNITE
		PULVERIZED LIGNITE * NO EC
		SPREADER-STOKER BOILER * NO EC
		TRAVEL GRATE (OVERFEED) STOKER BOILER * NO EC
	STEAM-LIQUID PETROLEUM GAS	GENERIC * 50/50 PROPANE/BUTANE * NO EC
	STEAM-MUNICIPAL SOLID WASTE	GENERIC * MASS FEED
		GENERIC * REFUSE DERIVED MSW
	STEAM-NATURAL GAS	GENERIC UTILITY BOILER
		LARGE BOILER * > 100 GJ/HR (100 MMBTU/HR) * NO EC
		SMALL BOILER * < 100 GJ/HR (100 MMBTU/HR) * NO EC
		TANGENTIALLY FIRED BOILER * NO EC
	STEAM-NUCLEAR	BOILING WATER REACTOR (GENERAL ELECTRIC BWR/6)
		PRESSURIZED WATER REACTOR (USDOE)
	STEAM-RESIDUAL OIL	GENERIC UTILITY BOILER
		UTILITY BOILER * LOW NOX BURNER
		GENERIC BOILER * GRADE 6 OIL * NO EC
		BOILER * SELECTIVE CATALYTIC REDUCTION
		TANGENTIALLY FIRED BOILER * GRADE 6 OIL * NO EC

PROCESS TYPE	PROCESS	TECHNOLOGY
ELECTRICITY GENERATION (continued)	STEAM-SHALE OIL	GENERIC UTILITY BOILER
	STEAM-WASTE OIL	GENERIC * NO EC
	STEAM-WOOD	GENERIC UTILITY BOILER
		GENERIC BARK FIRED UTILITY BOILER * NO EC
		GENERIC BOILER * WOOD/BARK MIX * NO EC
		GENERIC BOILER * NO EC
	TURBINE-KEROSENE	GENERIC * NO EC
	TURBINE-NATURAL GAS	GENERIC
		GENERIC * NO EC
		SELECTIVE CATALYTIC REDUCTION
		WATER INJECTION
	TURBINE-OIL	GENERIC * NO EC
	FUEL CELLS	11 MW PHOSPHORIC ACID CELL-NATURAL GAS
		11 MW PHOSPHORIC ACID CELL-NAPTHA

I. OTHER RELATED DATA ON ELECTRICITY, OIL REFINING AND DISTRICT HEAT USE

STRUCTURE OF SOURCES AND DEMAND IN ELECTRIC NE ORKS - GWh

– year 1990



note: Comas (in the figures) are points (full stop)

AMOUNT OF POWER INSTALLATIONS D.G.T.D.E.E. 39

ELECTRIC LINES

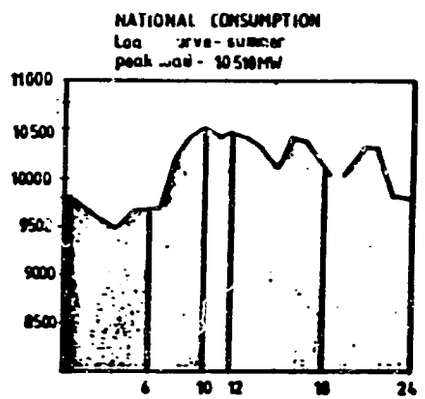
CONSTRUCTION VOLTAGE kV	OPERATING VOLTAGE kV	OVERHEAD LINES ONE CIRCUIT km	OVERHEAD LINES DOUBLE CIRCUIT km	CABLES km
750	750	154	-	-
400	400	3066	351	1
400	220	815	29	-
400	110	-	3	-
220	220	2117	1443	2
220	110	19	37	-
110	110	8662	8336	258
110	under 110	91	48	-
60 - 30		450	32	26
25 - 15		84692	3095	10867
10		251	1	8829
6 - 1		1182	77	7164
under 1		113630	1436	38081

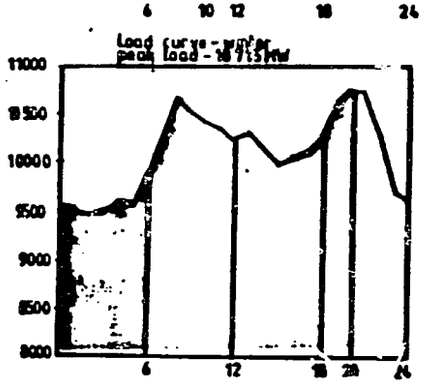
SUBSTATIONS

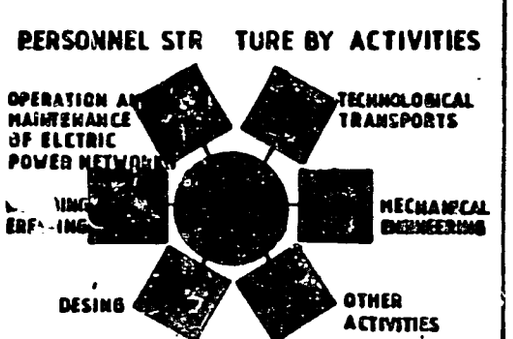
UPPER RATED VOLTAGE	NUMBER	NUMBER OF TRANSFORMERS	INSTALLED CAPACITY MVA
750	1	6	2500
400	23	73	13893
220	44	131	16386
110	845	1796	36942
60-30	25	53	309
25-15	446	823	2501
10	7	13	90
6-1	4	5	9

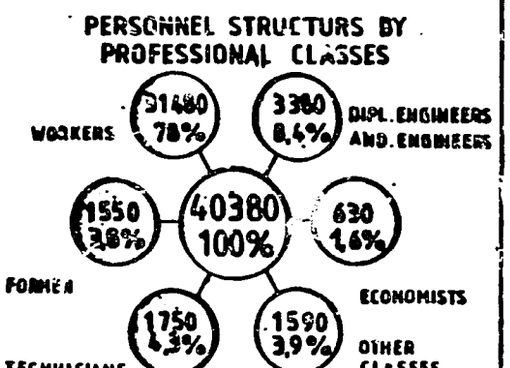
SUBSTATIONS UP TO 60 KV AND DISTRIBUTION POINTS

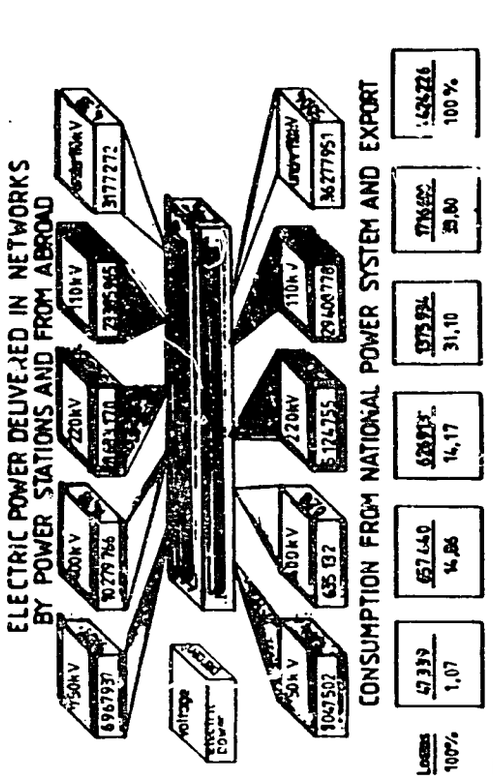
UPPER RATED VOLTAGE	NUMBER	NUMBER OF TRANSFORMERS	INSTALLED CAPACITY KVA
60-30	3	3	750
25-15	53416	58752	17453131
10	5516	6982	3652075
6-1	5754	6926	2989261

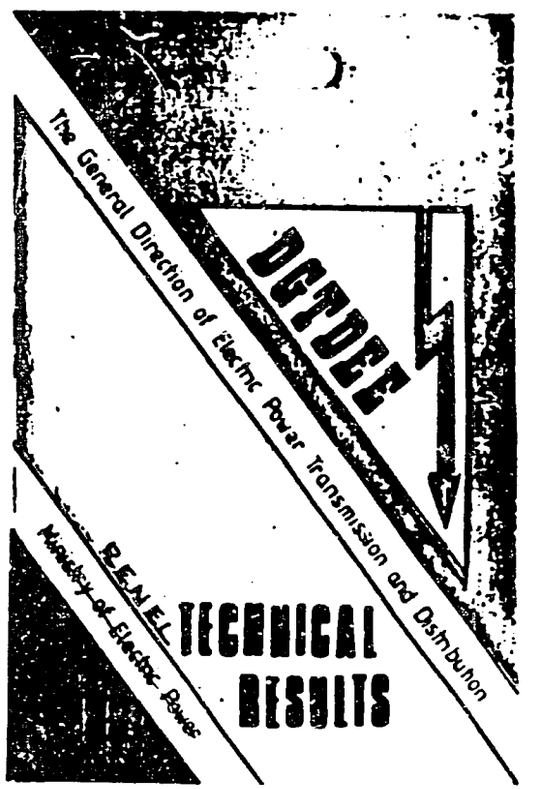

NATIONAL CONSUMPTION
11000
10500
10000
9500
9000
8500
6
10
12
18
24


11000
10500
10000
9500
9000
8500
8000
6
12
18
24


PERSONNEL STR TURE BY ACTIVITIES
OPERATION A
MAINTENANCE
OF ELECTRIC
POWER NETWO
TECHNOLOGICAL
TRANSPORTS
MECHANICAL
ENGINEERING
DESING
OTHER
ACTIVITIES


PERSONNEL STRUCTURS BY
PROFESSIONAL CLASSES
WORKERS
31480
78%
3380
8,4%
DIPL. ENGINEERS
AND. ENGINEERS
1550
3,8%
40380
100%
630
1,6%
FORMER
ECONOMISTS
1750
4,3%
1590
3,9%
TECHNICIANS
OTHER
CLASSES


ELECTRIC POWER DELIVERED IN NETWORKS
BY POWER STATIONS AND FROM ABROAD
750kV
6967937
500kV
10279766
220kV
110kV
31772772
36277951
110kV
29400778
220kV
5174755
400kV
635192
750kV
1047502
CONSUMPTION FROM NATIONAL POWER SYSTEM AND EXPORT
47339
1,07
657640
14,86
626953
14,17
1375594
31,10
1776660
40,80
4426726
100%
Losses
100%


The General Direction of Electric Power Transmission and Distribution
DGTDEE
Ministry of Electric Power
RENEL
TECHNICAL
RESULTS

PRICES FOR DELIVERED ELECTRICITY

Will have to be tested

No.	Electric energy (the sort of voltage)	Prices for active electric energy (for RENEL)								Price for reactive electric energy delivered to the consumers with montnly average power factor (cosφ) smaller than
		A. For large consumers which has appropiate measuring instrumentation				B. For large industrial consumers and similar which has not appropiate measuring equipment		C. For the rest of consumers (also the average price)		
		Power		Energy						
		Lei/kW/year		Lei/kwh		Lei/kwh		lei/kwh		Lei/kVAr h
		Peak hours	Rest of hours	Peak hours	Rest of hours	Peak hours	Rest of hours	-		-
1.	Low voltage (o,1-1 kv including)	5664	23o4	2,89	o,68	4,88	1,76	2,2o		o,22o
2.	Medium voltage (1-11o kv excluding)	3528	144o	2,23	o,8o	3,33	1,22	1,52		o,15o
3.	High voltage (11o kv and higher)	1668	7o8	2,23	o,8o	2,68	1,o1	1,2o		o,11o

Includes Residential ?
0.65 lei/kwh

ENERGY PRICING REFORM STUDY DATA NEEDS

OIL PRODUCTS

Product - U/M	Provided 1989	Required 1990	Provided 1990
Crude oil processed - 1000 tons	25,674.8	24,448.9	23,565.9
Gasoline - 1000 tons	5,226.5	4,832.6	4,621.5
Diesel fuel - 1000 tons	6,978.9	6,426.4	6,213.9
Black oil (including recovered oil) - 1000 tons	8,594.0	8,344.2	8,057.5
Lubrication oil (including regenerated oil) - tons	453.3	64,406.5	44,758.7
Ethylene - tons	273,864.2	294,020.0	239,794.0
Propilene - tons	220,290.6	220,830.0	178,295.0
Syntetic rubber - tons	122,249.9	116,855.0	101,356.0
PVC - 100% tons	175,374.1	164,625.0	153,671.0
Small density poliethylene - 100% tons	78,338.5	76,460.0	69,957.0
High density poliethylene - 100% tons	54,393.3	64,650.0	49,551.0
Polipropylene - 100% tons	10,486.6	11,550.0	7.022.0

292

3/.../91

THERMAL POWER CONSUMPTION AND COVERING MODULES

Final heat consumption is covered both by fuel direct burning and by generation in a centralised way of the thermal energy under the form of hot steam and water.

In Romania, heat resulted from fuel direct burning represents about 52% of the total heat, about 4o% of the final energy consumtion respectively while the final energy consumption and the thermal energy generated in a centralised way represents about 48% of the total heat, about 36% of the final energy consumption respectively.

In Romania, heat consumption per capita is about 2ooo kgcf as against about 37oo kgcf in the ex-socialist countries including U.S., about 5ooo kgcf in the N America, about 2loo kgcf in the western countries (according to the EC-UNO reports for Europe).

In Romania, the low temperature heat (up to loo°C) represents about 3o% of the final heat consumption, about 24% of the final heat consumption respectively, as against 57% of the final heat consumption and 38% of the final energy demand in the EEC member countries.

The average temperature heat (lco-3oo°C) represents about 25% of the final heat consumption and about 19% of the final energy consumption as against 12% of the total heat demand and about 8% of the final energy demand in the EEC member countries.

The share of high temperature heat (over 3oo°) within the final heat consumption is of 45%, while within the final power consumption is 35%, as compared to 31% of the total heat demand and 21% of the final power demand which are the values for all the ECE countries.

The evolution of thermal power consumption as steam and hot water for all the country and for the consumer structure is the following:

- mil.Gcal.

	1972	1975	1980	1985	1989
Total gross consumtion	97.7	128.9	162,7	161.9	181.4
out of which: industry and other sectors:	89.4	116.6	142.7	141.1	158.6
- domestic:	8.3	12.3	2o.o	2o.8	23.1

The thermal power industrial consumption as steam and hot water has increased starting with 1972 up to 1980 by about 65%;with respect to its share within the total consumption this share has decreased continuously reaching the value of 87.7% in 1980.After 1980 up to now ,as a result of the industry up-dating process,of the changes in technology,and of the re-designing of certain products it has been possible to maintain the share at 87±1%.

The covering of the demand for thermal power for heating and for household hot water out of centralised sources has started during 1959-1960.

As the degree of urbanisation increased and localities developed conditions for the extension of heat centralized supply have been created. At present the consumption as warm and hot water for heating and domestic hot water preparation represents about 13% of the total consumption.

At present :

Over 90% of the thermal power ,as steam and hot water which is centralised generated is consumed in urban areas; the inhabiatnts of these areas represent 50% of the country population.

The thermal energy consumption of localities with a population of more than 50000 inhabitants represent two-thirds of the centralized generated thermal power.

The structure of thermal power generation as steam and hot water according to the source type is shown in the following way:

	1972	1975	1980	1985 %
Generated power Romania total	100	100	100	100
out of which				
CHPP	48	55	55	56
TP	52	45	45	44

The thermal power consumption,as warm and hot water,for domestic heating requirements is satisfied as follows:

- in towns with a population of over 100000 inhabitants, where both industrial and domestic consumptions are concentrated higher than 450 Gcal/h from CHPP with 120 MW units(major heating consumption) and of 50 MW (major industrial consumption);
- in towns with less than 100,000 inhabitants:
  . for heat consumtions between 75-150 Gcal/h from CHPP with 12 MW units for population concentrated in areas adjacent to coal basins. For the coal transport to longer distances the erection of

unique HP equipped with loo and 5o Gcal/h HWB is justified;

- for domestic heat consumption between 3o-75 Gcal/h loo,5o and lo Gcal/h HWB a5e to be taken into consideration. The erection of CHPP with 4 MW units is justified in places where renewable energy resources dannot be used for other purposes or have local coal deposi as well as in cities where the major industrial consumption can be coupled with the domestic consumption;

- for domestic heat consumption less than 3o Gcal/h the erection of HP equipped with boilers of different distributed capacities that lo,5,3 andl Gcal/h is justified;

- for domestic consumption less than 3 Gcal the erection of distr thermal plants equipped with o,25 Gcal/h hot water boilers, thermal plants for buildings equipped with o.o8 Gcal/h hot water boilers are to be taken into consideration;

- to supply heat to private houses stoves with solid,liquid and gaseous fuel are to be used further on either individually or coupled for the preparation of the domestic hot water with individual installa tions with solar panels, waste-heat boilers or electric boilers.

295

PREŢURI DE LIVRARE PENTRU ENERGIA TERMICĂ

Nr. crt.	Energia termică pe niveluri de presiune	Consumatori şi revînzători racordaţi la ieşirea din centrala electrică de termoficare sau din centrala termică (D.E.E.)		Consumatori şi revînzători racordaţi la reţelele de transport	
		Preţ pentru 1 Gcal/h putere termică maximă anuală contractată - Lei/an	Preţ pentru energie Lei/Gcal	Preţ pentru 1 Gcal/h putere termică maximă anuală contractată Lei/an	Preţ pe energie Lei/Gcal
1.	Apă fierbinte		371,o	-	415
2.	Abur în funcţie de presiunea la ieşirea din centrală, în ata:				
	2.1. Presiuni pînă la 19 ata inclusiv	3o7274	4b2	442411	486
	2.2. Presiuni peste 19 ata:				
	2.2.1. din prizele turbinelor	3o7274	532	442411	556
	2.2.2. din cazane	3o7274	614	442411	638

3. Condensat nereturnat şi apă demineralizată livrată : 39,8 lei/mc

4. Apă fierbinte nereturnată şi apă dedurizată livrată: 2o,2 lei/mc

CONVERSION TABLES

Length

1 meter	=	39.3701 inches
	=	3.28084 feet

Area

1 square meter	=	10.7639 square feet
1 square kilometer	=	0.386102 square miles
	=	100 hectares
1 hectare	=	10,000 square meters
	=	2.47105 acres

Volume

1 liter	=	0.0353147 cubic foot
	=	0.264172 US gallon
	=	0.001 cubic meter
	=	0.219969 Imperial gallon
1 US barrel	=	5.6146 cubic feet
	=	0.158987 cubit meter
	=	42 US gallons
	=	34.9726 Imperial gallons

Mass

1 kilogram	=	2.20462 pounds
1 short ton (US)	=	2,000 pounds
	=	0.907185 tonne
	=	0.892857 long ton
1 tonne (metric)	=	1,000 kilograms
	=	2,204.62 pounds
	=	0.984207 long ton
	=	1.10231 short tons
1 long ton (Imperial)	=	2,240 pounds
	=	1.12 short tons
	=	1.01605 tonnes

Energy and power

1 international table (IT) calorie	=	4.1868 joules
1 kilocalorie (IT)	=	1.163 watt hours
1 kilowatt hour	=	3412.14 BTUs
	=	895.845 kilocalories (IT)
	=	3.6 megajoules
	=	1.34102 horsepower-hours
1 metric horsepower	=	735.499 watts
	=	542.476 foot pounds force/second
	=	0.98632 Imperial horsepower
1 kilowatt	=	737.562 foot pounds force/second
	=	1.35962 metric horsepower

Approximate heat energy content of fuels

	BTU/lb	MJ/kg
Crude oil	18,300-19,500	42.6-45.4
Gasoline	20,500	47.7
Kerosene	19,800	46.1
Benzole	18,100	42.1
Ethanol	11,600	27.0
Gas oil	19,200	44.7
Fuel oil (bunker)	18,300	42.6
Coal (bituminous)	10,200-14,600	23.7-34.0
LNG (natural gas)	22,300	51.9

Product specific gravity ranges

	Specific Gravity	Barrels per tonne
Crude oil	0.80-0.97	8.0-6.6
Aviation gasoline	0.70-0.78	9.1-8.2
Motor gasoline	0.71-0.79	9.0-8.1
Kerosene	0.78-0.84	8.2-7.6
Gas oil	0.82-0.90	7.8-7.1
Diesel oil	0.82-0.92	7.8-6.9
Lubricating oil	0.85-0.95	7.5-6.7
Fuel oil	0.92-0.99	6.9-6.5
Asphaltic bitumen	1.00-1.10	6.4-5.8

Converting into Barrels-of-Oil Equivalent (BOE)

Energy forms are converted into a common unit, BOE, based on fuel oil equivalent at 18,600 Btu/lb as follows:

Electricity	600 kwh	1.0000
Regular Gasoline	1 bbl	0.8470
Premium	1 bbl	0.8624
Kerosene	1 bbl	0.8798
Diesel Oil	1 bbl	0.9328
LPG	1 bbl	0.6384
Aviation Gas	1 bbl	0.8475
Aviation Turbo	1 bbl	0.798
Fuel Oil		
Pitch	1 bbl	1.0058
PFC	1 bbl	1.0197
Coal (10,000 BTU/lb)	1 MT	3.530
Alcohol	1 bbl	0.5561
Bagasse	1 MT	1.440
Coconut Oil	1 bbl	1.000

ABBREVIATIONS

BHP	–	brake horsepower
BTU	–	British thermal unit
CIF	–	cost including insurance and freight
CPI	–	consumer price index
DWT	–	deadweight tons or tonnage
GNP	–	gross national product
GWH	–	gigawatt-hour
KV	–	kilovolt
KW	–	kilowatt
KWH	–	kilowatt-hour
MB	–	thousand barrels
MBCD	–	thousand barrels per calendar day
MBSD	–	thousand barrels per stream day
MJ	–	megajoules
MMB	–	million barrels
MMBOE	–	million barrels-of-oil equivalent
MT	–	metric tons
MVA	–	megavolt ampere
MW	–	megawatt
bbl	–	barrel

247

TABLE B-58.—*Consumer price indexes, major expenditure classes, 1946–90*

[1982–84 = 100]

Year or month	All items	Food and beverages		Housing				Apparel and upkeep	Transportation	Medical care	Entertainment	Other goods and services	Energy [3]
		Total [1]	Food	Total	Shelter	Fuel and other utilities [2]	Household furnishings and operation						
1946	19.5		19.8					34.4	16.7	12.5			
1947	22.3		24.1					39.9	18.5	13.5			
1948	24.1		26.1					42.5	20.6	14.4			
1949	23.8		25.0					40.8	22.1	14.8			
1950	24.1		25.4					40.3	22.7	15.1			
1951	26.0		28.2					43.9	24.1	15.9			
1952	26.5		28.7					43.5	25.7	16.7			
1953	26.7		28.3		22.0	22.5		43.1	26.5	17.3			
1954	26.9		28.2		22.5	22.6		43.1	26.1	17.8			
1955	26.8		27.8		22.7	23.0		42.9	25.8	18.2			
1956	27.2		28.0		23.1	23.6		43.7	26.2	18.9			
1957	28.1		28.9		24.0	24.3		44.5	27.7	19.7			21.5
1958	28.9		30.2		24.5	24.8		44.6	28.6	20.6			21.5
1959	29.1		29.7		24.7	25.4		45.0	29.8	21.5			21.9
1960	29.6		30.0		25.2	26.0		45.7	29.8	22.3			22.4
1961	29.9		30.4		25.4	26.3		46.1	30.1	22.9			22.5
1962	30.2		30.6		25.8	26.3		46.3	30.8	23.5			22.6
1963	30.6		31.1		26.1	26.6		46.9	30.9	24.1			22.6
1964	31.0		31.5		26.5	26.6		47.3	31.4	24.6			22.5
1965	31.5		32.2		27.0	26.6		47.8	31.9	25.2			22.9
1966	32.4		33.8		27.8	26.7		49.0	32.3	26.3			23.3
1967	33.4	35.0	34.1	30.8	28.8	27.1	42.0	51.0	33.3	28.2	40.7	35.1	23.8
1968	34.8	36.2	35.3	32.0	30.1	27.4	43.6	53.7	34.3	29.9	43.0	36.9	24.2
1969	36.7	38.1	37.1	34.0	32.6	28.0	45.2	56.8	35.7	31.9	45.2	38.7	24.8
1970	38.8	40.1	39.2	36.4	35.5	29.1	46.8	59.2	37.5	34.0	47.5	40.9	25.5
1971	40.5	41.4	40.4	38.0	37.0	31.1	48.6	61.1	39.5	36.1	50.0	42.9	26.5
1972	41.8	43.1	42.1	39.4	38.7	32.5	49.7	62.3	39.9	37.3	51.5	44.7	27.2
1973	44.4	48.0	48.2	41.2	40.5	34.3	51.1	64.6	41.2	38.8	52.9	46.4	29.4
1974	49.3	55.5	55.1	45.8	44.4	40.7	56.8	69.4	45.8	42.4	56.9	49.8	38.1
1975	53.8	60.2	59.8	50.7	48.8	45.4	63.4	72.5	50.1	47.5	62.0	53.9	42.1
1976	56.9	62.1	61.6	53.8	51.5	49.4	67.3	75.2	55.1	52.0	65.1	57.0	45.1
1977	60.6	65.8	65.5	57.4	54.9	54.7	70.4	78.6	59.0	57.0	68.3	60.4	49.4
1978	65.2	72.2	72.0	62.4	60.5	58.5	74.7	81.4	61.7	61.8	71.9	64.3	52.5
1979	72.6	79.9	79.9	70.1	68.9	64.8	79.9	84.9	70.5	67.5	76.7	68.9	65.7
1980	82.4	86.7	86.9	81.1	81.0	75.4	86.3	90.9	83.1	74.9	83.6	75.2	86.0
1981	90.9	93.5	93.6	90.4	90.5	86.4	93.0	95.3	93.2	82.9	90.1	82.6	97.7
1982	96.5	97.3	97.4	96.9	96.9	94.9	98.0	97.8	97.0	92.5	96.0	91.1	99.2
1983	99.6	99.5	99.4	99.5	99.1	100.2	100.2	100.2	99.3	100.6	100.1	101.1	99.9
1984	103.9	103.2	103.2	103.5	104.0	104.8	101.9	102.1	103.7	106.8	103.8	107.9	100.9
1985	107.6	105.6	105.6	107.7	109.8	106.5	103.8	105.0	106.4	113.5	107.9	114.5	101.6
1986	109.6	109.1	109.0	110.9	115.8	104.1	105.2	105.9	102.3	122.0	111.6	121.4	88.2
1987	113.6	113.5	113.5	114.2	121.3	103.0	107.1	110.6	105.4	130.1	115.3	128.5	88.6
1988	118.3	118.2	118.2	118.5	127.1	104.4	109.4	115.4	108.7	138.6	120.3	137.0	89.3
1989	124.0	124.9	124.1	123.0	132.8	107.8	111.2	118.6	114.1	149.3	126.5	147.7	94.3
1990	130.7	132.1	132.4	128.5	140.0	111.6	113.3	124.1	120.5	162.8	132.4	159.0	102.1
1989: Jan	121.1	122.0	122.2	120.7	129.8	106.0	110.9	115.3	111.1	143.8	123.8	143.4	89.0
Feb	121.6	122.7	122.9	121.1	130.3	105.9	110.9	115.3	111.6	145.2	124.3	144.1	89.3
Mar	122.3	123.3	123.5	121.5	131.2	105.9	110.5	119.3	111.9	146.1	124.7	144.4	89.8
Apr	123.1	124.0	124.2	121.6	131.2	106.2	110.7	120.9	114.6	146.8	125.4	144.7	94.9
May	123.8	124.7	124.9	122.1	131.8	107.0	110.0	120.4	116.0	147.5	125.5	145.4	97.4
June	124.1	124.9	125.0	122.9	132.3	109.2	111.1	117.8	115.9	148.5	126.2	146.3	59.0
July	124.4	125.4	125.5	123.9	133.6	109.7	111.4	115.0	115.4	149.7	126.9	147.3	98.5
Aug	124.6	125.6	125.8	124.2	134.1	109.7	111.4	115.0	114.3	150.7	127.3	148.7	97.0
Sept	125.0	125.9	126.1	124.3	134.1	109.7	111.7	120.0	113.7	151.7	127.8	151.2	95.9
Oct	125.6	126.3	126.5	124.4	134.8	108.0	111.9	122.7	114.5	152.7	128.4	151.8	94.6
Nov	125.9	126.7	126.9	124.5	135.2	107.5	111.9	122.1	115.0	153.9	128.6	151.9	93.2
Dec	126.1	127.2	127.4	124.9	135.6	108.4	111.7	119.2	115.2	154.4	129.1	152.9	93.2
1990: Jan	127.4	130.0	130.4	125.9	136.3	110.8	112.1	116.7	117.2	155.9	129.9	154.0	97.6
Feb	128.0	130.9	131.3	126.1	136.6	110.2	112.8	120.4	117.1	157.5	130.4	154.7	96.4
Mar	128.7	131.2	131.5	126.8	137.8	109.9	112.8	125.4	116.8	158.7	130.9	155.2	95.5
Apr	128.9	131.0	131.3	126.8	138.0	109.4	112.8	126.7	117.3	159.8	131.4	155.8	95.7
May	129.2	131.1	131.3	127.1	138.3	109.9	113.2	125.5	117.7	160.8	131.7	156.6	96.7
June	129.9	131.7	132.0	128.3	139.5	112.2	113.1	123.3	118.2	161.9	131.9	157.8	99.5
July	130.4	132.4	132.7	129.2	141.1	111.3	113.6	120.8	118.4	163.5	132.7	159.2	98.9
Aug	131.6	132.7	132.9	130.2	142.4	112.7	113.3	122.2	120.6	165.0	133.0	160.4	103.6
Sept	132.7	133.0	133.2	130.5	142.3	114.0	113.8	126.8	123.0	165.8	134.1	162.6	108.8
Oct	133.5	133.4	133.6	130.5	142.4	113.4	114.2	128.4	125.8	167.1	134.3	163.2	111.4
Nov	133.8	133.7	134.0	130.4	142.4	112.9	113.8	127.5	126.9	168.4	134.4	163.6	110.9
Dec	133.8	133.9	134.2	130.5	142.7	112.7	113.7	125.3	127.2	169.2	134.6	164.5	110.1

[1] Includes alcoholic beverages, not shown separately.
[2] See table B-59 for components.
[3] See tables B-60 for definition and B-59 for components.

Note.—Data beginning 1978 are for all urban consumers; earlier data are for urban wage earners and clerical workers. Data beginning 1983 incorporate a rental equivalence measure for homeowners' costs and therefore are not strictly comparable with earlier figures.

Source: Department of Labor, Bureau of Labor Statistics.

TABLE B-59.—*Consumer price indexes, selected expenditure classes, 1946–90*

[1982-84 = 100, except as noted]

Year or month	Food and beverages				Shelter					Fuel and other utilities				
		Food				Renters' costs					Household fuels			
	Total [1]	Total	At home	Away from home	Total	Total [2]	Rent, residential	Homeowners' costs [2]	Home maintenance and repairs	Total	Total	Fuel oil and other household fuel commodities	Gas (piped) and electricity	Other utilities and public services
1946		19.8					25.0					7.9	18.3	
1947		24.1	25.8				25.8					9.0	18.2	
1948		26.1	28.0				27.5					10.6	18.7	
1949		25.0	26.9				28.7					10.9	19.2	
1950		25.4	27.3				29.7					11.3	19.2	
1951		28.2	30.3				30.9					11.8	19.3	
1952		28.7	30.8				32.2					12.1	19.5	
1953		28.3	30.3	21.5	22.0		33.9		20.5	22.5		12.6	19.9	
1954		28.2	30.1	21.9	22.5		35.1		20.9	22.6		12.6	20.2	
1955		27.8	29.5	22.1	22.7		35.6		21.4	23.0		12.7	20.7	
1956		28.0	29.6	22.6	23.1		36.3		22.3	23.6		13.3	20.9	
1957		28.9	30.6	23.4	24.0		37.0		23.2	24.3		14.0	21.1	
1958		30.2	32.0	24.1	24.5		37.6		23.6	24.8		13.7	21.9	
1959		29.7	31.2	24.8	24.7		38.2		24.0	25.4		13.9	22.4	
1960		30.0	31.5	25.4	25.2		38.7		24.4	26.0		13.8	23.3	
1961		30.4	31.8	26.0	25.4		39.2		24.8	26.3		14.1	23.5	
1962		30.6	32.0	26.7	25.8		39.7		25.0	26.3		14.2	23.5	
1963		31.1	32.4	27.3	26.1		40.1		25.3	26.6		14.4	23.5	
1964		31.5	32.7	27.8	26.5		40.5		25.8	26.6		14.4	23.5	
1965		32.2	33.5	28.4	27.0		40.9		26.3	26.6		14.6	23.5	
1966		33.8	35.2	29.7	27.8		41.5		27.5	26.7		15.0	23.6	
1967	35.0	34.1	35.1	31.3	28.8		42.2		28.9	27.1	21.4	15.5	23.7	46.6
1968	36.2	35.3	36.3	32.9	30.1		43.3		30.6	27.4	21.7	16.0	23.9	47.1
1969	38.1	37.1	38.0	34.9	32.6		44.7		33.2	28.0	22.1	16.3	24.3	48.4
1970	40.1	39.2	39.9	37.5	35.5		46.5		35.8	29.1	23.1	17.0	25.4	50.0
1971	41.4	40.4	40.9	39.4	37.0		48.7		38.6	31.1	24.7	18.2	27.1	53.4
1972	43.1	42.1	42.7	41.0	38.7		50.4		40.6	32.5	25.7	18.3	28.5	56.2
1973	48.8	48.2	49.7	44.2	40.5		52.5		43.6	34.3	27.5	21.1	29.9	57.8
1974	55.5	55.1	57.1	49.8	44.4		55.2		49.5	40.7	34.4	33.2	34.5	60.7
1975	60.2	59.8	61.8	54.5	48.8		58.0		54.1	45.4	39.4	36.4	40.1	63.9
1976	62.1	61.6	63.1	58.2	51.5		61.1		57.6	49.4	43.3	38.8	44.7	67.7
1977	65.8	65.5	66.8	62.6	54.9		64.8		62.0	54.7	49.0	43.9	50.5	70.8
1978	72.2	72.0	73.8	68.3	60.5		69.3		67.2	58.5	53.0	46.2	55.0	73.7
1979	79.9	79.9	81.8	75.9	68.9		74.3		71.0	64.8	61.3	62.4	61.0	74.3
1980	86.7	86.8	88.4	83.4	81.0		80.9		82.4	75.4	74.8	86.1	71.4	77.0
1981	93.5	93.6	94.8	90.9	90.5		87.9		90.7	85.4	87.2	104.6	81.9	84.3
1982	97.3	97.4	98.1	95.8	96.9		94.6		96.4	94.9	95.6	103.4	93.2	93.3
1983	99.5	99.4	99.1	100.0	99.1	103.0	100.1	102.5	99.9	100.7	100.5	97.2	101.5	99.5
1984	103.2	103.2	102.8	104.2	104.0	108.6	105.3	107.3	103.7	104.8	104.0	99.4	105.4	107.2
1985	105.6	105.6	104.3	108.3	109.8	115.4	111.8	113.1	106.5	106.5	104.5	95.9	107.1	112.1
1986	109.1	109.0	107.3	112.5	115.8	121.9	118.3	119.4	107.9	104.1	99.2	77.6	105.7	117.9
1987	113.5	113.5	111.9	117.0	121.3	128.1	123.1	124.8	111.8	103.0	97.3	77.9	103.8	120.1
1988	118.2	118.2	116.6	121.8	127.1	133.6	127.8	131.1	114.7	104.4	98.0	78.1	104.6	122.9
1989	124.9	125.1	124.2	127.4	132.8	138.9	132.8	137.3	118.0	107.8	100.9	81.7	107.5	127.1
1990	132.1	132.4	132.3	133.4	140.0	146.7	138.4	144.6	122.2	111.6	104.5	99.3	109.3	131.7
1987 Jan	122.0	122.2	121.2	124.7	129.8	135.2	130.5	134.4	116.1	106.0	98.7	80.5	105.1	125.9
Feb	122.7	122.9	122.0	125.2	130.3	136.3	130.9	134.7	117.1	105.9	98.6	81.4	104.9	126.0
Mar	123.3	123.5	122.7	125.7	131.2	138.6	131.1	135.0	117.1	105.9	98.5	81.5	104.8	125.9
Apr	124.0	124.2	123.5	126.2	131.2	137.9	131.4	135.4	117.3	106.2	98.8	82.5	105.0	126.2
May	124.7	124.9	124.4	126.7	131.8	137.8	131.7	136.2	117.4	107.0	99.6	81.5	106.1	127.0
June	124.9	125.0	124.3	127.1	132.3	138.7	132.3	136.5	118.3	109.2	103.2	80.2	110.5	127.1
July	125.4	125.5	124.8	127.8	133.6	141.5	133.0	137.3	118.4	109.7	103.7	79.7	111.1	127.7
Aug	125.6	125.8	124.9	128.1	134.1	141.5	133.5	138.1	118.5	109.7	103.7	78.9	111.3	127.8
Sept	125.9	126.1	125.0	128.8	134.1	139.4	133.9	138.9	118.6	109.7	103.5	79.3	111.0	128.1
Oct	126.3	126.5	125.4	129.1	134.8	140.0	134.7	139.7	118.6	108.0	101.0	82.0	107.6	127.6
Nov	126.7	126.9	125.8	129.5	135.2	140.1	135.2	140.3	119.3	107.5	99.9	83.9	106.1	127.9
Dec	127.2	127.4	126.5	129.8	135.6	140.1	135.5	140.9	119.5	108.4	101.2	88.7	107.0	128.2
1990 Jan	130.0	130.4	131.0	130.3	136.3	142.0	135.8	141.1	120.4	110.8	104.5	113.1	107.5	129.3
Feb	130.9	131.3	132.1	131.0	136.6	143.5	136.0	141.0	120.8	110.2	103.1	95.4	108.3	130.0
Mar	131.2	131.5	131.9	131.8	137.8	144.8	136.5	142.2	121.2	109.9	102.3	91.5	107.9	130.7
Apr	131.0	131.3	131.1	132.5	138.0	144.7	137.0	142.5	121.2	109.4	101.2	89.6	106.8	130.9
May	131.1	131.3	130.9	133.0	138.3	144.4	137.3	143.1	122.2	109.9	101.9	88.0	107.8	131.2
June	131.7	132.0	131.7	133.4	139.5	145.3	137.9	144.4	121.8	112.2	105.4	84.9	112.4	131.8
July	132.4	132.7	132.5	133.9	141.1	148.7	138.7	145.4	122.1	111.3	104.5	82.7	111.7	130.8
Aug	132.7	132.9	132.7	134.3	142.4	150.7	139.4	146.5	121.2	112.7	105.6	91.8	111.6	132.8
Sept	133.0	133.2	132.9	134.6	142.3	148.9	140.0	147.0	124.6	114.0	107.6	104.4	112.4	132.9
Oct	133.4	133.6	133.4	135.0	142.4	148.9	140.5	147.2	123.4	113.4	106.4	118.5	109.0	133.4
Nov	133.7	134.0	133.8	135.4	142.4	149.0	140.7	147.3	123.9	112.9	105.4	117.0	108.0	133.7
Dec	133.9	134.2	133.8	135.7	142.7	149.5	141.1	147.5	123.8	112.7	105.6	114.1	108.6	132.7

[1] Includes alcoholic beverages, not shown separately.
[2] December 1982 = 100

See next page for continuation of table.

299

TABLE B-59.—*Consumer price indexes, selected expenditure classes, 1946–90*—Continued

[1982-84=100, except as noted]

Year or month	Transportation								Medical care		
	Total	Private transportation						Public transportation	Total	Medical care commodities	Medical care services
		Total [3]	New cars	Used cars	Motor fuel [4]	Automobile maintenance and repairs	Other				
1946	16.7	18.3			14.5	15.8		9.4	12.5	34.2	10.4
1947	18.5	20.8	34.1		16.4	17.1		9.9	13.5	36.7	11.3
1948	20.6	23.0	37.3		18.6	18.1		11.2	14.4	38.6	12.1
1949	22.1	24.4	40.8		19.1	18.6		12.4	14.8	39.2	12.5
1950	22.7	24.5	41.1		19.0	18.9		13.4	15.1	39.7	12.8
1951	24.1	25.6	43.1		19.5	20.4		14.8	15.9	40.8	13.4
1952	25.7	27.3	46.8		20.0	20.8		15.8	16.7	41.2	14.3
1953	26.5	27.8	47.2	26.7	21.2	22.0		16.8	17.3	41.5	14.8
1954	26.1	27.1	46.5	22.7	21.8	22.7		18.0	17.8	42.0	15.3
1955	25.8	26.7	44.8	21.5	22.1	23.2		18.5	18.2	42.5	15.7
1956	26.2	27.1	46.1	20.7	22.8	24.2		19.2	18.9	43.4	16.3
1957	27.7	28.6	48.5	23.2	23.8	25.0		19.9	19.7	44.6	17.0
1958	28.6	29.5	50.0	24.0	23.4	25.4		20.9	20.6	46.1	17.9
1959	29.8	30.8	52.2	26.8	23.7	26.0		21.5	21.5	46.8	18.7
1960	29.8	30.6	51.5	25.0	24.4	26.5		22.2	22.3	46.9	19.5
1961	30.1	30.8	51.5	26.0	24.1	27.1		23.2	22.9	46.3	20.2
1962	30.8	31.4	51.3	28.4	24.3	27.5		24.0	23.5	45.6	20.9
1963	30.9	31.6	51.0	28.7	24.2	27.8		24.3	24.1	45.2	21.5
1964	31.4	32.0	50.9	30.0	24.1	28.2		24.7	24.6	45.1	22.0
1965	31.9	32.5	49.7	29.8	25.1	28.7		25.2	25.2	45.0	22.7
1966	32.3	32.9	48.8	29.0	25.6	29.2		26.1	26.3	45.1	23.9
1967	33.3	33.8	49.3	29.9	26.4	30.4	37.9	27.4	28.2	44.9	26.0
1968	34.3	34.8	50.7	(5)	26.8	32.1	39.2	28.7	29.9	45.0	27.9
1969	35.7	36.0	51.5	30.9	27.6	34.1	41.6	30.9	31.9	45.4	30.2
1970	37.5	37.5	53.0	31.2	27.9	36.6	45.2	35.2	34.0	46.5	32.5
1971	39.5	39.4	55.2	33.0	28.1	39.3	48.6	37.8	36.1	47.3	34.7
1972	39.9	39.7	54.7	33.1	28.4	41.1	48.9	39.3	37.3	47.4	35.9
1973	41.2	41.0	54.3	35.2	31.2	43.2	48.4	39.7	38.8	47.5	37.5
1974	45.8	46.2	57.9	36.7	42.2	47.6	50.2	40.6	42.4	49.2	41.4
1975	50.1	50.6	62.9	43.8	45.1	53.7	53.5	43.5	47.5	53.3	46.6
1976	55.1	55.6	66.9	50.3	47.0	57.6	61.8	47.8	52.0	56.5	51.3
1977	59.0	59.7	70.4	54.7	49.7	61.9	67.2	50.0	57.0	60.2	56.4
1978	61.7	62.5	75.8	55.8	51.8	67.0	69.9	51.5	61.8	64.4	61.2
1979	70.5	71.7	81.8	60.2	70.1	73.7	75.2	54.9	67.5	69.0	67.2
1980	83.1	84.2	88.4	62.3	97.4	81.5	84.3	69.0	74.9	75.4	74.8
1981	93.2	93.8	93.7	76.9	108.5	89.2	91.4	85.6	82.9	83.7	82.8
1982	97.0	97.1	97.4	88.8	102.8	96.0	97.7	94.9	92.5	92.3	92.6
1983	99.3	99.3	99.9	98.7	99.4	100.3	98.8	99.5	100.6	100.2	100.7
1984	103.7	103.6	102.8	112.5	97.9	103.8	103.5	105.7	106.8	107.5	106.7
1985	106.4	106.2	106.1	113.7	98.7	106.8	109.0	110.5	113.5	115.2	113.2
1986	102.3	101.2	110.6	108.8	77.1	110.3	115.1	117.0	122.0	122.8	121.9
1987	105.4	104.2	114.6	113.1	80.2	114.8	120.8	121.1	130.1	131.0	130.0
1988	108.7	107.6	116.9	118.0	80.9	119.7	127.9	123.3	138.6	139.9	138.3
1989	114.1	112.9	119.2	120.4	88.5	124.9	135.8	129.5	149.3	150.8	148.9
1990	120.5	118.8	121.0	117.6	101.2	130.1	142.5	142.6	162.8	163.4	162.7
1989: Jan	111.1	109.8	119.5	120.5	79.6	122.4	133.5	127.5	143.8	145.0	143.5
Feb	111.6	110.3	119.6	120.5	80.3	123.3	134.3	128.1	145.2	145.8	145.1
Mar	111.9	110.7	119.6	120.5	81.5	123.5	134.5	128.2	146.1	147.2	145.9
Apr	114.6	113.6	119.4	120.7	92.1	123.8	134.7	128.4	146.8	148.4	146.4
May	116.0	115.0	119.5	121.0	96.6	124.3	135.6	128.9	147.5	150.0	146.9
June	115.9	114.9	119.1	121.3	96.0	124.5	135.9	129.6	148.5	151.0	147.9
July	115.4	114.3	118.6	121.1	94.4	124.8	135.6	129.7	149.7	151.4	149.3
Aug	114.3	113.1	117.7	120.3	91.0	125.4	135.7	130.1	150.7	152.1	150.4
Sept	113.7	112.4	117.0	119.8	88.8	126.2	135.7	130.1	151.7	153.3	151.3
Oct	114.5	113.3	118.6	119.7	88.9	126.7	137.1	130.6	152.7	154.1	152.3
Nov	115.0	113.7	120.5	120.1	87.2	126.7	138.2	131.3	153.9	155.3	153.6
Dec	115.2	113.9	121.8	119.7	85.8	126.9	139.0	131.9	154.4	156.0	154.1
1990: Jan	117.2	115.9	122.3	118.9	91.4	127.3	140.3	134.2	155.9	156.9	155.7
Feb	117.1	115.6	121.9	117.4	90.6	127.6	140.8	136.7	157.5	158.6	157.2
Mar	116.8	115.1	121.3	116.6	89.3	128.8	140.7	139.1	158.7	159.9	158.5
Apr	117.3	115.5	120.7	116.2	91.2	129.4	140.8	140.3	159.8	161.3	159.4
May	117.7	115.9	120.7	116.9	92.5	129.4	140.8	140.9	160.8	162.2	160.5
June	118.2	116.4	120.3	117.6	94.6	129.6	141.0	141.5	161.9	163.3	161.5
July	118.4	116.6	119.8	118.2	94.3	130.2	142.1	141.6	163.5	164.1	163.4
Aug	120.6	119.0	119.5	118.3	103.2	130.4	142.4	141.9	165.0	164.8	165.0
Sept	123.0	121.4	119.0	118.3	112.0	131.5	143.0	144.0	165.8	166.0	165.8
Oct	125.8	124.2	120.5	118.1	118.9	132.1	144.8	146.0	167.1	166.8	167.2
Nov	126.9	125.1	122.1	117.2	119.0	132.5	146.2	150.3	168.4	167.8	168.6
Dec	127.2	125.1	123.5	117.1	117.1	132.5	146.7	154.4	169.2	169.1	169.3

[3] Includes direct pricing of new trucks and motorcycles beginning September 1982.
[4] Includes direct pricing of diesel fuel and gasohol beginning September 1981.
[5] Not available.

Note.—Data beginning 1978 are for all urban consumers; earlier data are for urban wage earners and clerical workers. See also Note, Table B-58.

Source: Department of Labor, Bureau of Labor Statistics.

380

TABLE B-60.—*Consumer price indexes, commodities, services, and special groups, 1946–90*

[1982–84 = 100]

Year or month	All items	Commodities					Services			Special indexes			
		All commodities	Food	Commodities less food			All services	Medical care services	Services less medical care	All items less food	All items less energy	All items less food and energy	Energy[1]
				All	Durable	Nondurable							
1946	19.5	22.9	19.8	26.3	29.2	23.6	14.1	10.4	.....	19.8	.....	.....	.....
1947	22.3	27.6	24.1	29.7	31.7	27.1	14.7	11.3	.....	21.7	.....	.....	.....
1948	24.1	29.6	26.1	31.9	34.0	29.2	15.6	12.1	.....	23.3	.....	.....	.....
1949	23.8	28.8	25.0	31.5	34.5	28.7	16.4	12.5	.....	23.5	.....	.....	.....
1950	24.1	29.0	25.4	31.4	34.9	28.6	16.9	12.8	.....	23.8	.....	.....	.....
1951	26.0	31.6	28.2	33.8	37.5	30.8	17.8	13.4	.....	25.3	.....	.....	.....
1952	26.5	32.0	28.7	34.1	38.0	31.0	18.6	14.3	.....	25.9	.....	.....	.....
1953	26.7	31.9	28.3	34.2	37.7	31.2	19.4	14.8	.....	26.4	.....	.....	.....
1954	26.9	31.6	28.2	33.8	36.8	31.4	20.0	15.3	.....	26.6	.....	.....	.....
1955	26.8	31.3	27.8	33.6	36.1	31.4	20.4	15.7	.....	26.6	.....	.....	.....
1956	27.2	31.6	28.0	33.9	36.1	32.0	20.9	16.3	.....	27.1	.....	.....	.....
1957	28.1	32.6	28.9	34.9	37.2	32.9	21.8	17.0	22.8	28.0	28.9	28.9	21.5
1958	28.9	33.3	30.2	35.3	37.8	33.1	22.6	17.9	23.6	28.6	29.7	29.6	21.5
1959	29.1	33.3	29.7	35.8	38.4	33.5	23.3	18.7	24.2	29.2	29.9	30.2	21.9
1960	29.6	33.6	30.0	36.0	38.1	34.1	24.1	19.5	25.0	29.7	30.4	30.6	22.4
1961	29.9	33.8	30.4	36.1	38.1	34.3	24.5	20.2	25.4	30.0	30.7	31.0	22.5
1962	30.2	34.1	30.6	36.3	38.5	34.5	25.0	20.9	25.9	30.3	31.1	31.4	22.6
1963	30.6	34.4	31.1	36.6	38.6	34.8	25.5	21.5	26.3	30.7	31.5	31.8	22.6
1964	31.0	34.8	31.5	36.9	39.0	35.1	26.0	22.0	26.8	31.1	32.0	32.3	22.5
1965	31.5	35.2	32.2	37.2	38.8	35.6	26.6	22.7	27.4	31.6	32.5	32.7	22.9
1966	32.4	36.1	33.8	37.7	38.9	36.4	27.6	23.9	28.3	32.3	33.5	33.5	23.3
1967	33.4	36.8	34.1	38.6	39.4	37.6	28.8	26.0	29.3	33.4	34.4	34.7	23.8
1968	34.8	38.1	35.3	40.0	40.7	39.1	30.3	27.9	30.8	34.9	35.9	36.3	24.2
1969	36.7	39.9	37.1	41.7	42.2	40.9	32.4	30.2	32.9	36.8	38.0	38.4	24.8
1970	38.8	41.7	39.2	43.4	44.1	42.5	35.0	32.3	35.6	39.0	40.3	40.8	25.5
1971	40.5	43.2	40.4	45.1	46.0	44.0	37.0	34.7	37.5	40.8	42.0	42.7	26.5
1972	41.8	44.5	42.1	46.1	46.9	45.0	39.4	35.9	38.9	42.0	43.4	44.0	27.2
1973	44.4	47.8	48.2	47.7	48.1	46.9	40.1	37.5	40.6	43.7	46.1	45.6	29.4
1974	49.3	53.5	55.1	52.8	51.5	52.9	43.8	41.4	44.3	48.0	50.6	49.4	38.1
1975	53.8	58.2	59.8	57.6	57.4	57.0	48.0	46.6	48.3	52.5	55.1	53.9	42.1
1976	56.9	60.7	61.6	60.5	60.9	59.5	52.0	51.3	52.2	56.0	58.2	57.4	45.1
1977	60.6	64.2	65.5	63.0	64.4	62.5	56.0	56.4	55.9	59.6	61.9	61.0	49.4
1978	65.2	68.8	72.0	67.6	68.6	65.5	60.8	61.2	60.7	63.9	66.7	65.5	52.5
1979	72.6	76.6	79.9	75.3	75.4	74.6	67.5	67.2	67.5	71.2	73.4	71.9	65.7
1980	82.4	86.0	86.8	85.7	83.0	88.4	77.9	74.8	78.2	81.5	81.9	80.8	86.0
1981	90.9	93.2	93.6	93.1	89.6	96.7	88.1	82.8	88.7	90.4	90.1	89.2	97.7
1982	96.5	97.0	97.4	96.9	95.1	98.3	96.0	92.6	96.4	96.3	96.1	95.8	99.2
1983	99.6	99.8	99.4	100.0	99.8	100.0	99.4	100.7	99.2	99.7	99.6	99.8	99.9
1984	103.9	103.2	103.2	103.1	105.1	101.7	104.6	106.7	104.4	104.0	104.3	104.6	100.9
1985	107.6	105.4	105.6	105.2	106.8	104.1	109.9	113.2	109.6	108.0	108.4	109.1	101.6
1986	109.6	104.4	109.0	101.7	106.6	98.5	115.4	121.9	114.6	109.8	112.6	113.5	88.2
1987	113.6	107.7	113.5	104.3	108.2	101.8	120.2	130.0	119.1	113.6	117.2	118.2	88.6
1988	118.3	111.5	118.2	107.7	110.4	105.8	125.7	138.3	124.3	118.3	122.3	123.4	89.3
1989	124.0	116.7	125.1	112.0	112.2	111.7	131.9	148.9	130.1	123.7	128.1	129.0	94.3
1990	130.7	122.8	132.4	117.4	113.4	119.9	139.2	162.7	136.8	130.3	134.7	135.5	102.1
1989: Jan.	121.1	113.9	122.2	109.2	112.5	107.1	128.9	143.5	127.3	120.8	125.5	126.4	89.0
Feb.	121.6	114.3	122.9	109.5	112.4	107.6	129.4	145.1	127.8	121.3	126.0	126.9	89.3
Mar.	122.3	115.2	123.5	110.5	111.9	109.4	130.0	145.9	128.3	122.0	126.7	127.6	89.8
Apr.	123.1	116.7	124.2	112.5	111.8	112.8	130.2	146.4	128.5	122.9	127.1	128.0	94.9
May	123.8	117.5	124.9	113.2	111.9	113.9	130.8	146.9	129.1	123.3	127.6	128.3	97.4
June	124.1	117.2	125.0	112.8	112.1	113.1	131.6	147.9	129.9	123.9	127.7	128.5	99.0
July	124.4	117.0	125.5	112.1	111.9	112.2	132.5	149.3	130.8	124.2	128.2	129.0	98.5
Aug.	124.6	116.7	125.8	111.6	111.4	111.5	133.1	150.4	131.3	124.3	128.5	129.3	97.0
Sept.	125.0	117.3	126.1	112.4	111.3	112.9	133.4	151.3	131.6	124.8	129.1	130.0	95.9
Oct.	125.6	118.1	126.5	113.4	112.1	114.1	133.7	152.3	131.8	125.4	129.9	130.9	94.6
Nov.	126.9	118.3	126.9	113.4	113.0	113.6	134.1	153.6	132.1	125.6	130.4	131.3	93.2
Dec.	126.1	118.2	127.4	113.0	113.5	112.6	134.6	154.1	132.6	125.8	130.6	131.5	93.2
1990: Jan.	127.4	119.9	130.4	114.1	113.8	114.2	135.4	155.7	133.6	126.7	131.5	132.0	97.6
Feb.	128.0	120.6	131.3	114.6	113.7	115.0	136.0	157.2	133.9	127.3	132.3	132.8	96.4
Mar.	128.7	121.1	131.5	115.4	113.4	116.5	136.9	158.5	134.7	128.1	133.3	133.9	95.5
Apr.	128.9	121.4	131.3	115.8	113.1	117.4	137.1	159.4	134.9	128.4	133.5	134.2	95.7
May	129.2	121.4	131.3	115.9	113.2	117.5	137.6	160.5	135.3	128.7	133.7	134.4	96.7
June	129.9	121.6	132.0	115.8	112.9	117.6	138.8	161.5	136.5	129.4	134.2	134.8	99.5
July	130.4	121.6	132.7	115.5	113.0	117.0	139.9	163.4	137.5	130.0	134.8	135.5	98.9
Aug.	131.6	122.8	132.9	117.2	113.9	119.9	140.9	165.0	138.5	131.3	135.6	136.4	103.6
Sept.	132.7	124.6	133.2	119.8	117.8	124.1	141.4	165.8	139.0	132.6	136.3	137.2	108.8
Oct.	133.5	126.1	133.6	121.6	118.6	126.8	141.7	167.2	139.1	133.5	136.9	137.8	111.4
Nov.	133.8	126.3	134.0	121.7	116.1	126.6	142.0	168.6	139.4	133.7	137.2	138.2	110.9
Dec.	133.8	126.0	134.2	121.4	118.5	125.7	142.3	169.3	139.7	133.7	137.6	138.3	110.1

[1] Household fuels—gas (piped), electricity, fuel oil, etc.—and motor fuel. Motor oil, coolant, etc. also included through 1982.

NOTE: Data beginning 1978 are for all urban consumers; earlier data are for urban wage earners and clerical workers. See also Note, Table B-58.

SOURCE: Department of Labor, Bureau of Labor Statistics.

301