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with enrichments of up to 89%. The process is based on synthetic chemicals that can reversibly bind oxygen at low temperatures and release it at elevated temperatures. The operation is in a temperature range of 70° to 220°F, so low grade waste heat can be used to drive the process, and the external energy required for produce oxygen can be reduced.

4.5.5 Iron and Steel

"Steel – A National Resource for the Future" broadly defines four areas of R&D to shape the industry in 2020. These include production efficiency (which encompasses energy efficiency), recycling, environmental engineering, and product development. The goal of increasing steel production to over 70% of recovered scrap would have major implications for energy use. DOE and the two major steel industry trade groups have signed a R&D collaborative compact to work together on the first three of the four research areas. Below, we discuss some of the process areas within which energy and other savings are likely to be achieved from technical breakthroughs.

Activity will be largely dictated by the viability of different iron making processes that are under development. R&D effort should focus on developing a process scheme that incorporates both iron making and steel making into one system with thin strip casting as a final product. The effort should incorporate a coal-based reductant process which can be coupled with steel making operations and simultaneously produce power in a combined cycle that includes both gas and steam turbines.

Steel making processes currently utilize computer technology, primarily to implement prespecified procedures in a timely manner. There is very little feedback in these systems to either enhance process efficiency or improve the product quality. Key process parameters should be identified so that interactive logic and high-speed computer systems can be used to control/modify/maintain these process parameters to obtain a quality product. Such an intelligent-processing approach is essential for the production of so called "cleaner steel" with low residual elements.

The development of sensors for all aspects of process control and for enabling process changes with a feedback system is essential for improving process efficiency and optimizing different stages of the melting, casting, thermomechanical processing, and final heat treatment. Applications of novel ideas and approaches need to be explored and transfer of technologies available from defense and chemical processing industries may be a fruitful approach.

4.5.6 Metal Casting

A diverse group of CEOs and presidents from the foundry, die casting, and foundry supply companies co-authored "Beyond 2000: A Vision for the American Metal Casting Industry." This vision of the industry identifies six critical areas: production efficiency; recycling; pollution prevention; application development; process controls; and new technology development. The specific goals include increasing productivity by 15% and reducing energy consumption by 3-5% by 2010. The Cast Metals Coalition is preparing a R&D strategy to achieve these and other goals identified in the industry vision. Some examples of technology areas are given below.

Electromagnetic Casting: An electromagnetic field in a casting is used to induce eddy currents in the liquid metal that, together with the field, stir and contain the liquid metal in the casting. Two examples are discussed below:

EM Stirring: In continuous casting, the solidification process can be improved by EM stirring, producing better metallurgical results, improved internal quality of the casting, and even reduced meniscus instability and surface defects (Beitelman and Mulcahy 1994, Chang et al. 1995). The benefit from EM stirring takes the form of reduced wastage per cast. As a minimum, we expect that the present average yield of 55% for the industry can be increased to 65%, a savings of 130,000 tons per year, with an associated energy savings of 25 trillion Btu per year (American Foundrymen's Society 1995).

EM Confinement: In the presently dominant sheet-forming process, thick steel slabs are cast and then hot-rolled. Twin-roll casting with EM confinement has the potential to cast thin sheets by eliminating the hot-rolling stage, giving the sheet product an enormous economic advantage over products made by competing methods (Saucedo and Blazek 1994, Blazek et al. 1994) and completely by-passing an energy-intensive stage of production.

4.6 CONCLUSIONS

This chapter presents an approach to assessing the potential for efficiency to reduce energy use in the most diverse sector of the economy, the industrial sector; this approach represents a compromise between the desire for technology detail and the need to evaluate sector-wide energy use. The approach uses two publicly available models, Argonne's Long-term Industrial Energy Forecasting (LIEF) model and the Energy Information Administration's industrial module from the National Energy Modeling System (NEMS), to simulate a plausibly optimistic set of scenarios for additional energy savings, relative to an established base case (AEO97). The models are used to project what energy savings could arise from an 'invigorated effort' to put currently available or near commercial technologies into practice in industry. This invigorated effort is loosely characterized by either a combination of new policy initiatives or a more serious consideration of efficiency as a strategic concern of industrial decision makers.

Two efficiency cases are presented in order to project overall reductions in energy use by 2010. A reduction of 5-10% is projected to be technically feasible, given adequate policies or other incentives to expand the adoption of cost-effective measures. This is about 2.5 quads in the high case. The LIEF model projects that these reductions could arise from cost-effective investments defined by a capital recovery factor of 15% (about a seven year pay-back). The LIEF model does not assume that in every case all energy-efficiency investments are made, but an increased penetration rate of efficiency investment is assumed relative to the base case as a result of this 'invigorated effort'. For many of the energy-intensive industrial sectors, these projected energy savings are consistent with roughly doubling the current rates of capital stock replacement or doubling the rate of energy technology efficiency improvement that is currently represented in the NEMS model.

Since the models used to conduct the scenario analysis do not have a detailed, technology-specific representation of each major industrial sector, the chapter also provides illustrative examples of technologies for most of the energy-intensive industries. These are examples of technologies that have the potential to reduce energy use relative to current practices if widely adopted. These technology examples exhibit substantial energy savings relative to current industry practice, so they reinforce the fact that the model results are feasible. But one cannot expect these technologies to be adopted widely unless there is some invigorated effort to encourage their adoption. The slow turnover of the capital stock in the energy and capital intensive industries is one reason that this invigorated effort would be needed. Under conservative projections, in the near-term, many of these technologies (and the many others not listed here) are capable of reaching high levels of penetration but most will not achieve 100% penetration. However, the examples show that there are many ways in which efficiency in industry can be increased, given the right incentives; the examples help establish the technical plausibility of the projections.

The efficiency case projections also show that, on a percentage basis, there are more savings in 'light' non-energy-intensive industry vs. the 'heavy', energy-intensive sectors. This result arises from the LIEF model scenarios but, due to the structure of the model, does not have an analog in NEMS. Because the share of total production costs attributable to energy use in the non-energy-intensive sectors is very low (the manufacturing average is about 3% and most light industry is less), it is not surprising that the range of energy performance is quite broad. Energy-efficient technologies, in the form of motor systems as well as lighting and HVAC options (similar to those discussed in the commercial section of Chapter 3), represent cost-effective investment opportunities in light manufacturing. However, there may not have been a managerial or technical focus on energy efficiency in those industries. An 'invigorated effort' could provide this focus. On the other hand, to reduce energy use in 'heavy' industry, where considerable attention to efficiency has already been paid, low capital turnover rates and difficulty in financing medium to large investments may be the major impediments to accelerated improvements in energy utilization. This 'invigorated effort' in these sectors might require tax incentives, alternative financing arrangements, new developments that lower first cost, or demonstration projects that lower perceived risk. The diversity among these broad categories of industry implies that the mix of policies required to achieve the high-efficiency case may differ for the various types of industries, based on their current business and technical practices as well as current domestic and international market conditions.

For all of the industries discussed above, further progress in energy efficiency beyond 2010 requires further developments in technology. These developments may be *incremental* improvements (e.g., sensors, controls, and system/process modeling) or may be *fundamental* breakthroughs (e.g., catalysts, direct smelting, or bioprocessing). Incremental improvements need not be associated with 'small' efficiency changes. The ability to sense and adjust a process to achieve optimal operating conditions can have large effects on productivity and energy consumption. However, the search for totally new methods to produce a product with fundamental breakthroughs in chemistry, metallurgy, or biology offers another route to enhance productivity and lower energy use. These two avenues of R&D to create the manufacturing sector of 2020 are both being sought by private and private/public partnerships.

Table 4.15 summarizes the technology examples presented above. A rough categorization of incremental (I) and fundamental (F) has been made. Many of the underlying concepts in the examples apply to other sectors, while others are very process specific. This identification is made as well. In should be noted that the year 2010 designates current (on very near commercial) technologies, while the year 2020 designates technologies that will require further R&D, with no prediction of a commercialization date.

The range and types of technological solutions in industrial applications is quite large. Since energy represents a cost, and energy efficiency a potential source of profit, these technical solutions can fit within the economic goals of business. With the right incentives, higher energy efficiency of the magnitude projected here in the industrial sector is an achievable goal.

Table 4.15 Summary of Technology Examples

Example Taken From	Technology Example	Year	Type of change: incremental or fundamental	Concept applicable to other sectors	Saves fossil or electric energy
Aluminum	Improve Furnace Efficiency	2010	I	Y	EF
Aluminum	Materials Recycling	2010	I	Y	E
Aluminum	Improving Hall-Heroult Cell Efficiency	2010	I	N	E
Aluminum	Wettable Cathodes	2010*	I	N	E
Aluminum	Inert Anodes	2010*	I	N	E
Chemicals	Pinch Analytical Techniques	2010	I	Y	F
Chemicals	Advanced Distillation Control Techniques	2010	I	N	F
Chemicals	Flexible Chemical Processing Of Polymers	2020	F	N	F
Chemicals	Biological/Chemical Caprolactam Process	2020	F	N	F
Cross-cutting	Combined Heat and Power	2010	I	Y	EF
Cross-cutting	Motor Systems	2010	I	Y	E
Glass	Glass Batch/Cullet Preheater Technology	2010	I	Y	F
Glass	Advanced Burner Technology	2010	I	Y	F
Glass	Oxy-Fuel Process	2010	I	N	F
Glass	Producing Oxygen More Efficiently	2020	I	Y	E
Glass	Recovering Waste Heat	2020	I	Y	F
Glass	Maximize Combustion Efficiency	2020	I	Y	F
Glass	Optimizing Electric Boost	2020	I	N	F
Iron and Steel	Process Controls	2010	I	Y	EF
Iron and Steel	Hot Connection	2010	I	Y	F
Iron and Steel	Scrap Preheating	2010	I	Y	EF
Iron and Steel	Use Of DC, Rather Than AC, EAFs	2010	I	N	E
Iron and Steel	Coal Or Natural Gas Injection	2010	F	N	F
Iron and Steel	Direct Smelting /Reduction	2010	F	N	F
Iron and Steel	Process Controls And Sensors	2020	I	Y	EF
Iron and Steel	Direct Smelting & Thin Strip Casting	2020	F	N	EF
Metal Casting	Computer-Aided Casting Design	2010	I	Y	EF
Metal Casting	Optimized Coreless Induction Melting	2010	I	N	E
Metal Casting	Electromagnetic Stirring	2020	I	N	EF
Metal Casting	Electromagnetic Casting	2020	F	N	EF
Petroleum Refining	Utility System Improvements	2010	I	Y	F
Petroleum Refining	Process/Equipment Modifications	2010	I	N	F
Petroleum Refining	Development Of Improved Catalysts	2020	F	Y	F
Pulp and Paper	On-Machine Sensors For Paper Properties	2010	I	Y	F
Pulp and Paper	Multiport Cylinder Drying	2010	I	N	F
Pulp and Paper	Impulse Drying	2010	I	N	F
Pulp and Paper	Biomass Gasification	2010*	I	Y	EF
Pulp and Paper	Black Liquor Gasification	2010*	I	N	EF
Pulp and Paper	Sulfur Free Pulping	2020	F	N	EF
Pulp and Paper	Polyoxometalate Bleaching	2020	F	N	EF

* Based on the accelerated deployment described in Section 4.3.

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ENDNOTES

[1] Because they become very important in a low-carbon scenario, we have made an exception to this approach in the case of low-carbon technologies which are examined from the bottom-up. Unlike energy-efficiency technologies, there is no established modeling procedure or analysis method for assessing the penetration of low-carbon (especially low process carbon) technologies. Thus, we simply provide case studies and take their results as a lower bound on the potential.

[2] Differences in the industry subsector detail prevented us from doing a precise calibration of the two models. It is not clear that such a calibration would substantially improve our analysis for these purposes.

[3] Technologies that supplement the existing process (e.g., process controls) might penetrate rapidly, but most that are replacements for existing process will more likely follow the 'normal' turnover patterns. Technologies achieving rapid penetration include sensors and process control software and technologies that can save significant amounts of energy.

[4] The forest products industry includes pulp and paper, as well as lumber and wood products. This report focuses on the relatively more energy-intensive pulp and paper segment of the forest product industry.

[5] In particular, we do not change the underlying forecast for activity in the refining sector.

[6] The HE/LC case also includes low-carbon technologies described in Section 4.4. These low-carbon technologies are not explicitly captured in the computer model runs.

[7] Not all energy-intensive industries are "heavy." The metal casting industry, for example, consists of many small shops owned by small businesses. It is important to distinguish OIT's Industries of the Future and the "heavy industry" of Table 4.1. These "heavy" industries include non-vision industries such as food (SIC 20), non-refining petroleum (SIC 295, 299), stone, clay and cement (SIC 324-329), non-aluminum non-ferrous (SIC 3331, 3339, 3351, 3356, 3357, 3364, 3366, 3369). Conversely, the vision industries include wood and lumber (SIC 24), miscellaneous paper (SIC 265, 267), and miscellaneous chemicals (SIC 283, 285, 2879, 289), which are not included in the "heavy" industry of Table 4.1.

[8] These numbers are calculated from the numbers in Appendix A for Figure 16 in DOE (1995).

[9] Note that, in Figure 4.3, ATS in simple cycle power-only mode has a higher heat rate than the most efficient combined cycle turbine. However, even the power-only ATS emits far less CO_2 than the existing sources of power to the grid. In our calculation of the carbon reductions for ATS in power-only applications, we make the conservative assumption that the ATS has about the same emissions as new power plants. The carbon savings in this market come only from avoided T&D.

[10] As an average of 3 to 18 MW units (9 to 80 MW in multiple units), ATS are 43% efficient in simple cycle and can be 80 – 85% efficient (combined thermal and electric efficiency) when used for cogeneration (Hoffman, 1997).

[11] Constraints to growth of cogeneration have derived in part from the traditional requirement that steam and electricity loads be matched to maintain efficient and cost-effective operation of the cogenerator. The new ATS overcomes this problem by running efficiently at a wide range of electricity to thermal ratios. Cogeneration has also been constrained by environmental permitting, utility regulation, and utility competition. Together these factors explain why very efficient CHP technology still comprises a relatively small fraction of electricity and steam generation. When policies to promote CHP are instituted, however, this fraction can grow dramatically (Major 1995). Finland, Denmark, and the Netherlands have each achieved a contribution of about 30% of electricity production based on CHP.

[12] In the recuperator configuration hot exhaust gas from the turbine is used to preheat the air leaving the compressor prior to combusion, thereby reducing the amount of fuel required to reach the design turbine inlet temperature.

[13] See Appendix D-3 for details.

[14] Such reform would include standardized permits to reduce costs for small sites and a life cycle approach that takes into account power plant emissions and T&D for on site power permits.

[15] Current regulations, and some proposed utility deregulation legislation, include barriers to small on-site CHP. Both scenarios assume policies that elicit the cooperation of utilities in the increase in on-site generation. One scenario that could be imagined is that the utilities themselves finance and service these industrial ATS's for CHP and power generation.

[16] Carbon reductions from fuel switching were not included – a conservative assumption discussed in Apendix D-3.

[14]The calculations performed for both scenarios were reviewed by the American Forest and Paper Association and industry representatives (David Cooper and Delmar R. Raymond).

[18] The makeup of residual biomass and residue generation rates in various forest product and paper industries are described in Appendix D-5.

[19] Three large plants in the U.S. manufacture adipic acid and they are working with the EPA to reduce emissions (Boyd 1997). However, emissions from this process have increased by 9.9% since 1990.

[20] Many of the U.S. aluminum smelters are located in regions of the country with large hydropower resources, notably the Pacific Northwest (served by the Bonneville Power Administration), the Southeast (served by the Tennessee Valley Authority), and Northern New York. Under both scenarios, the aluminum smelters that would likely be converted first would be those in regions such as the Ohio River Valley that are dominated by coal-powered plants.

[21] 0.2 MtC = [(5 plants) * (190,000 tonnes of AL/plant)* (13,200 kWh/tonne of AL) * (89 gr of carbon per kWh) * 0.17]/1,000,000 grams/tonne.

[22] The carbon savings from the aluminum industry efficiency improvements that are already included in Section 4.2.2 must be subtracted in order to identify the increment that can be added by this analysis of alternative aluminum production cells. We calculate this as follows. Table 4.2 estimates that the aluminum industry as a whole will be 2% more efficient in its use of electricity in 2010 under the efficiency scenario, compared to the business-as-usual case. Under the assumption here that 5 of 22 smelters (23%) will be retrofitted with wettable cathodes that offer a 17% improvement in electricity efficiency, the nation's aluminum smelters as a whole would be 3.9% more efficient (3.9% = 0.23 * 17%). This represents a 1.9% efficiency improvement (or 0.09 MtC of emissions reductions) over the 2% that is assumed in the efficiency case in Section 4.2.2.

[23] 0.48 = (5 of 22 plants) * (50%) * 4.2 MtC.

[24] 1.0 MtC = [(10 plants) * (190,000 tonnes of AL/plant)* (13,200 kWh/tonne of AL) * (160 gr of carbon per kWh) * 0.25]/1,000,000 grams/tonne.

[25] The carbon savings from the aluminum industry efficiency improvements that are already included in Section 4.2.2 must be subtracted in order to identify the increment that can be added by this analysis of alternative production cells. We calculate this as follows. Table 4.2 estimates that the aluminum industry as a whole will be 3.8% more efficient in its use of electricity in 2010 under the high-efficiency/low-carbon scenario, compared to the business-as-usual case. Under the assumption here that 10 of 22 smelters (45%) will be retrofitted with inert anodes that offer a 25% improvement in electricity efficiency, the nation's aluminum smelters as a whole would be 11.4% more efficient (11.4% = 0.45 * 25%). This represents a 7.6% efficiency improvement (or 0.67 MtC of emissions reductions) over the 3.8% efficiency improvement that is assumed in Section 4.2.2.

[26] 0.6 MtC = (10 plants) * (190,000 tonnes of Al/plant) * (0.33 tonnes of C/tonne of AL).

[27] 1.91 MtC = (10 of 22 plants) * (100%) * 4.2 MtC.

[28] Note that almost none of the carbon savings due to Section 4.2.2's high-efficiency/low-carbon (HE/LC) case should be subtracted from this amount. The clinker replacement is not an efficiency increase, but a demand reduction. Thus, the drop in carbon emissions is nearly additive. We subtracted a very small amount because of the 8.1% reduction in cement industry energy use under the HE/LC scenario. The carbon savings due to a 5-20% reduction in demand is 2-4 MtC depending on the kiln technology. The amount we subtracted is about 5% of the total (0.06-0.08 MtC). If we assume that the penetration by 2010 is limited to the European owned firms (roughly half), then the carbon reduction is 1-2 MtC. Note that the HE/LC energy efficiency savings of Section 4.2.2 are equivalent to a carbon emissions reduction of just over 1 MtC depending on cement kiln technology.

[29] The Greenville Tube Company (GT) realized non-energy benefits ten times greater than the energy benefits when the company upgraded its motors. GT is a manufacturer of high-precision, small-diameter, stainless steel tubing. GT replaced an old motor and inefficient eddy current clutch drive with an energy-efficient motor with vector control. This new motor required fewer runs and produced far less scrap than the old system. The motor reduced annual energy consumption by 37% and resulted in savings of more than $77,000 annually from increased productivity, reduced scrap generation, and reduced energy costs.

Chapter 5

TRANSPORTATION SECTOR

5.1 INTRODUCTION

The trend of more than a decade of continuous energy-efficiency improvements in transportation, marked by a sharp decoupling of energy consumption and economic growth, appears to have come to an end. The transportation sector's energy use now appears to be growing at nearly the same rate as the gross domestic product (GDP).

From 1949 until 1973, energy use in the U.S. transportation sector grew at an average annual rate of 3.6% per year (EIA, 1996a, Table 2.1). In the years following the oil crisis of 1973-74 until the oil price collapse of 1986, that rate fell to only 0.6% per year.[1] This sharp decrease in growth was caused by a combination of market and non-market factors – sharply rising oil prices and, perhaps more important, strong expectations that prices would continue to escalate for the foreseeable future; threats of gasoline rationing and actual (though largely government-caused) local gasoline shortages; successes in government-sponsored R&D, especially in aeronautics; and new regulations, particularly the Corporate Average Fuel Economy (CAFE) standards for automobiles and light trucks. Some manifestations of the decrease in the growth of energy use during this period were:

- Between 1973 and 1988, new passenger cars increased their fuel economy from about 14 MPG to 28.6 MPG (EPA rated) (Heavenrich and Hellman, 1996, Table 1), a rate of 5% per year.

- During 1970-1987, commercial aviation decreased in energy intensity from 10,351 Btu per passenger-mile to 4,753 Btu/pm (Davis and McFarlin, 1996, Table 2.16) again at an average rate of 5% per year.

- During 1970-1994, the energy intensity of rail freight decreased from 691 Btu/ton-mile to 388 Btu/ton-mile, or 44% (Davis and McFarlin, 1996, Table 2.17), a rate of 2.4% per year.

Although changes in travel behavior, choice of vehicle size, changes in vehicle occupancy rates and other non-technological factors have a role in the rate of growth in transportation energy use, improved technological efficiency has been the most critical factor in energy trends. For example, had energy intensities not changed since 1972, commercial airlines would be using over twice the energy they use today (assuming today's number of passenger-miles of travel), and three quarters of the savings are due to technological improvements in aircraft (Davis and McFarlin, 1996, Table 2.21). Similarly, examination of the causes of substantial fuel economy gains by automobiles during the 1970s and 1980s show that the majority of the gains were achieved by improving technical efficiency, not by consumers moving to small cars. Between 1978 and 1984, only 7.8% of the period's MPG gain was achieved by shifts to smaller cars (Westbrook and Patterson, 1985). Between 1976 and 1989, the combination of weight reduction, improved transmissions, tires, and aerodynamics, widespread use of fuel injection, various engine improvements, improved lubricants, and wider use of front wheel drive accounted for about 70% of the total 8.4 MPG improvement during the period (Westbrook, 1989). In fact, the technology of automobiles has improved so much over the past few decades that if the 4,000 pound plus, 15.8 MPG automobile of 1975 were to be built with today's technology but *without any change in weight or horsepower*, it would get 26.4 MPG (Greene and Fan, 1994)! And although 85% of the improvement in rail freight energy efficiency came from increased loadings per car, much of the 85% resulted from improved communications and computing capability (other factors included changing composition of freight during this period and other operational improvements), and improved vehicle technology accounted for the remaining 15% (Greene, 1996).

Over the past ten years (1986-1996), the rate of growth of transportation energy use has averaged 1.6% per year, but in the past three years it accelerated to 2.2% per year, just below the rate of growth of GDP. Transportation energy efficiency, which improved significantly during the decade of the 1980s, appears to be stagnant (U.S. DOT/BTS, 1996, p. 87). The average fuel economy of new passenger cars has not improved significantly over the past decade. The average fuel economy of light-duty vehicles, new cars, and light trucks combined has not changed significantly since 1982 (Heavenrich and Hellman, 1996, Table 1) and, as a consequence, the average on-road fuel economy of the entire on-road light-duty vehicle fleet was only 1% higher in 1995 (the most recent year for which data are available) than in 1991 (U.S. DOT/FHWA, 1996, Table VM-1). Gasoline prices are now at pre-1973 levels and fuel economy standards have not been raised over 1985 levels. There are exceptions, however: commercial air travel and rail freight continue to make meaningful efficiency gains (U.S. DOT/BTS, 1996, p. 101). Overall, the transportation sector appears to have entered a period of growth in activity only slightly slower than that of GDP with only modest gains or no improvement in energy efficiency.

Despite these recent trends, the 1997 Annual Energy Outlook (AEO97) reference case forecast to 2015, which serves as the backdrop for this analysis, foresees very slow growth in transportation energy use (1.4%/yr.) accompanied by virtually no change in the prices of transportation fuels (0.2%/yr.). A modest rate of growth in vehicle travel (1.4%/yr.) together with MPG gains of 5.1 MPG for new passenger cars and 3.7 MPG for new light trucks over 1995 levels, combine to hold the growth of light-duty vehicle energy use to 1% per year through 2015. Every year since at least 1989, the AEO (among others) has forecasted continued light-duty vehicle fuel economy gains yet the actual fuel economy of light-duty vehicles as a whole has not improved. In some cases, energy prices have turned out to be lower and in other cases higher than expected. Apparently, technology that could have been used to improve fuel economy is either not being implemented, or is being used to provide some other feature that consumers value, such as performance. We expand on this point below in explaining why, in our "business-as-usual" (BAU) case, we forecast no improvement in light-duty vehicle fuel economy. We believe that, given low energy prices, plentiful oil supplies, no market disruptions, and no new energy policy initiatives, it is optimistic to expect continued energy-efficiency improvement and slow growth of energy use.

Current policy initiatives and activities to increase future transportation energy efficiency are relatively modest. Except for light-duty highway vehicles, the federal government does not regulate transportation fuel efficiency. The National Highway Traffic Safety Administration has the power to raise CAFE standards for autos and light trucks, but there seems little chance that it will do so at the present time. The Energy Policy Act contains provisions to move alternative fuel vehicles into the fleet (fleet vehicle requirements and altfuel tax credits), but these provisions are limited, and congressional support for coercive action is nonexistent. On the other hand, there are important R&D initiatives that could play a role in improving transportation fuel efficiency, particularly the long-standing NASA and Defense Department programs in aeronautic design and the Partnership for a New Generation of Vehicles (PNGV), a joint government/industry research effort aimed primarily at developing vehicles with up to three times current fuel economy levels.

The newest of federal initiatives aimed at improving transportation fuel efficiency, PNGV has reorganized and redirected the federal government's R&D effort in advanced automotive technologies towards the ambitious goal of tripling automotive fuel economy and reducing pollutant emissions while at the same time preserving consumer amenities and holding down costs. Current PNGV spending is on the order of $250 million dollars (the exact amount is subject to debate because of definitional problems of which efforts are actually dedicated to PNGV goals) (U.S. Congress, OTA, 1995), with the largest government share coming from DOE's Electric and Hybrid Vehicle Program. Current PNGV thinking seems aimed at an advanced hybrid-electric vehicle, with research efforts aimed particularly at advanced materials, high-power energy storage devices, fuel cells and improved engines, lean NO_X catalysts (to allow necessary emission control for lean-burn engines including diesels and direct injection stratified charge engines), and improved electric drives, including power electronics.

In this chapter, the potential for these and other energy-efficient and low-CO_2 technologies to cost-effectively reduce transport sector greenhouse gas emissions is examined. Three transportation sector scenarios were developed using the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) model, AEO97 version (see Overview of Methodology box), with reference case assumptions about macroeconomics and energy prices (Decision Analysis Corp., 1996; EIA, 1994). These are labeled the (1) "business-as-usual" (BAU), (2) "efficiency" (EFF), and (3) "high-efficiency/low-carbon" (HE/LC) cases. Our business-as-usual case differs from the AEO97 reference case only in that new light-duty vehicle fuel economy is held constant at current levels throughout the period of the forecast. In the reference case, it improves at an average annual rate of 0.4%.

The efficiency and high-efficiency/low-carbon scenarios differ from each other less in effort than in outcome. In our view, the improvements postulated in the efficiency scenario are *likely* to be forthcoming if appropriate policy measures are undertaken and research efforts intensified. In contrast, because the outcomes postulated in the high-efficiency/low-carbon scenario require technological breakthroughs, they require a certain degree of luck to be achieved by 2010. There are no credible methods to accurately gauge the probability of such breakthroughs; we believe they stand a decent chance of occurring with an intensification of research efforts, but we stop short of claiming that they are a likely outcome of such an intensification. In other words, the efficiency scenario represents what is often called a "most likely" or "probable" scenario, in the authors' judgment. The high-efficiency/low-carbon scenario is better described as an "optimistic" or "possible" scenario. However, both are predicted on a major intensification of R&D effort plus significant policy measures aimed at pushing the market towards giving fuel efficiency a much higher priority.

The efficiency scenario is created by assuming earlier introduction of advanced fuel economy technology and by adding certain key technologies that are absent from the AEO97 reference case. It assumes the introduction of advanced ethanol-from-biomass technology in 2005, technology which the U.S. DOE is currently intensively involved in developing. In the efficiency case, technology development is incremental rather than revolutionary. Nonetheless, the efficiency case does presume a major energy technology R&D effort, perhaps two to ten times the level of current government programs. It also assumes that policies necessary to draw energy-efficiency technology into the market are implemented, as needed. In other words, effective policy actions, whether they be increased fuel economy standards, revenue neutral feebates, fuel taxes, public information or some other initiative, are assumed to have been put in place. This point is critical, because AEO97 forecasts inexpensive, plentiful fossil fuels, and because the goal of preventing global climate change is a classic public good that markets on their own will generally ignore.

Overview of Methodology

Producing scenarios for this analysis comprised three principle steps: (1) developing assumptions about future advances in energy technology for transportation, (2) entering these assumptions into an integrating model to predict their market acceptance and impact on transportation energy use and, (3) adjusting the model's predictions for analyses and forecasts done "on the side". Because of time and budget constraints, no attempt was made by the transportation sector team to integrate our scenarios with those of other energy-using sectors to produce an economy-wide scenario. The methodology is therefore a partial analysis of the effects of technology on the transportation sector, assuming no interaction with other sectors of the economy.

Obviously, there is no sure way to predict the evolution of technology. Thus, the key to developing a useful technology scenario is clearly documenting assumptions, and also demonstrating that the assumptions are consistent with recent advances in technology by referencing published scientific and technical reports. Wherever possible, we base our assumptions on objective technology assessments, such as the Office of Technology Assessment's (1995) examination of the potential for advanced automotive technology. The result of this step is a list of specific technologies with the following data for each, (1) date of initial market introduction, (2) quantitative impact on energy efficiency (e.g., % fuel economy improvement over a baseline vehicle) and, (3) incremental cost to the buyer.

We used the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS), Transportation Sector Model as a tool for integrating the technology assumptions and predicting their impact on energy use. NEMS is undoubtedly the most fully documented (U.S. DOE/EIA, 1994; 1995a, 1995b, 1996a, 1996b), most rigorously peer reviewed (e.g., NRC,) and most thoroughly tested comprehensive, national energy model. The NEMS Transportation Sector Model comprises a set of submodels for each transport mode that range in complexity from the highly detailed light-duty vehicle model to much simpler models for waterborne transport and rail freight.

The NEMS light-duty vehicle model requires an itemization of each technology, as well as its applicability to each of six passenger car and six light truck classes. In addition to introduction date, cost and fuel economy improvement potential, interactions (incompatibilities, complementarities, etc.) among technologies must be carefully specified. NEMS predicts market penetration over time based on cost-effectiveness and time since introduction, but also by applicability and interactions with other technologies. These predictions reflect normal requirements for testing of new technologies, as well as turnover of the stock of manufacturing capital. The Freight Truck and Air Travel Models also require a list of technologies, introduction dates and efficiency improvement estimates, but market penetration is handled somewhat more mechanistically. In both cases, new technologies are introduced when the price of fuel crosses a threshold price. For Rail Freight and Waterborne Freight, one must directly specify a rate of efficiency improvement.

Given technology assumptions, other macroeconomic inputs, and the energy and economic predictions of the 1997 Annual Energy Outlook Reference Case Projection, the NEMS Transportation Model predicts new vehicle sales, used vehicle scrappage, vehicle utilization, and fuel consumption by model and vehicle type. These endogenous predictions are sensitive to economic variables. For example, improving energy efficiency will result in some degree of increased vehicle travel due to the lower cost of fuel per mile. Based on the composition of demand by fuel type, NEMS also forecasts carbon emissions, as well. For the largest transport modes, the evolution of vehicle stocks over time are explicitly calculated in great detail. In general, the technological characteristics of a vehicle are determined in the year in which it is manufactured. NEMS then exhaustively accounts for the numbers of vehicles by type, class, and vintage, as well as which technologies have been applied to these vehicles. As a result, NEMS's representation of the dynamics of technological change are quite meticulous.

Finally, two parts of the scenario analysis were done "off line," thus necessitating some straightforward adjustments to the NEMS forecasts. The estimation of market supply and demand for cellulosic ethanol as a blending component of conventional gasoline was calculated by means of a spreadsheet model. The supply and demand studies upon which this analysis were based were simply too recently produced (they are based on draft reports) to have already been incorporated by the EIA into the NEMS model structure at the time. Also, we chose to introduce advanced direct injection diesel passenger cars and light trucks using the NEMS model algorithm for conventional gasoline vehicles rather than as alternative fuel vehicles. This reflects our belief that the new advanced diesels will be almost indistinguishable from gasoline vehicles from the consumers' perspective (with the exception of their cost and fuel economy, variables the NEMS model takes into account). A drawback of this choice is that we sacrificed the NEMS model's ability to automatically account for the additional diesel use and, therefore, had to adjust for it after the fact. Several additional calculations were made based on NEMS outputs. The NEMS model's output includes the market penetration of each technology by vehicle type and class. Using this information together with the input assumptions about technology costs and fuel economy improvement we were able to compute measures of the overall cost-effectiveness of the sum total of all technologies applied to passenger cars and light trucks.

The high-efficiency/low-carbon case begins with the efficiency case assumptions and then goes beyond incremental technological advances and postulates breakthroughs in fuel cell technology for light-duty vehicles, as well as major aerodynamic and engine efficiency gains for commercial aircraft, among other selected technological achievements. It also includes more optimistic assumptions about biomass ethanol production costs. It is not the intent of this scenario to include all possible technological advances, but rather to focus on a few that could have major long-run implications for greenhouse gas emissions from the transportation sector. We could, as well, have assumed technological breakthroughs for battery-electric or compressed or liquefied natural gas vehicles, both of which have some potential to reduce carbon emissions compared to petroleum-based fuels. The more breakthroughs one assumes, however, the lower the probability that the scenario will actually occur. Furthermore, in the long-run, no single technology appears to have a greater potential to reduce carbon emissions from transportation than the fuel cell. We do not assume a target and tradeable permit system equivalent to $50/T of carbon in the high-efficiency scenario. We do assume in both scenarios that significant policies similar to this are in place to encourage producers to produce and consumers to choose fuel-efficient, low-carbon technologies.

Although the focus of this study is on the year 2010, forecasts to 2015 are also presented because changing the technology of transportation energy use takes more than one decade. Once a technology is market ready, two to three years of testing and certification are still required prior to introduction. Even then, most technologies will not appear on all makes and models simultaneously due to the need to replace plant and equipment in an efficient manner. Finally, expected lifetimes for transportation vehicles are counted in decades. The median expected lifetime of a passenger car is now 14 years, truck lifetimes average 16 years, marine vessel and aircraft life expectancies are at least twice that (Davis and McFarlin, 1996, Tables 3.6 and 3.7). Thus, the full impact of technologies introduced between now and 2010 will not be apparent in 2010. We include the year 2015 to illustrate this fact. In all cases, a normal rate of replacement of capital stock is assumed, both in the production of transportation vehicles and in their purchase and scrappage. That is to say, no changes are made to the NEMS model to accelerate the turnover of capital stocks.

Results of the three scenario projections are compared with EIA's AEO97 projections in Table 5.1. In the business-as-usual case, transportation energy use grows from 25.5 quads in 1997 to 32.3 quads in 2010 and to 34.0 quads in 2015. Emissions of carbon increase as well, up 26% in 2010 and 33% higher by 2015. The efficiency scenario achieves roughly a 10% reduction in energy use and a 12% reduction in transportation sector emissions versus the business-as-usual case by 2010. Reductions in 2010 versus the AEO97 reference case are slightly less, 7% for energy and 9% for carbon emissions. Use of cellulosic ethanol as a blending component in gasoline reduces greenhouse gas emissions by 2-3% over and above the reduction in energy use. The greatest reductions in fossil fuel use are achieved by rail freight (-16%), light-duty highway vehicles (-12%), and commercial air travel (-11%). Energy use in 2015 is actually below that of 2010 in the efficiency scenario because of the greater penetration of new, efficient equipment into the stocks of transportation vehicles. Transportation uses 28.2 quads of energy, 17% below the business-as-usual case but still 10% over 1997 levels. Emissions of carbon are down by 20% over the business-as-usual case, still 6% higher than in 1997. The high-efficiency/low-carbon scenario reduces energy use and carbon emissions by another 4% in 2010 and by an additional 5% in 2015. By 2015, transportation sector carbon emissions are projected to be below the 1997 level in the high-efficiency/low-carbon scenario.

Table 5.1 Comparison of Three Transportation Energy Scenarios to the AEO97 Reference Case

Energy Use (quads)			
	1997	2010	2015
Business-as-Usual	25.5	32.3	34.0
Reference Case	25.4	31.4	32.3
Efficiency	25.4	29.2	28.6
High-Eff/Low-Carbon	25.3	27.8	26.4
Carbon Emissions (MtC)			
	1997	2010	2015
Business-as-Usual	487	616	646
Reference Case	485	598	614
Efficiency	485	543	532
High-Eff/Low-Carbon	484	513	485

Note: Carbon emissions include emissions from the generation of electricity for electric vehicles. Reference case assumptions about electric vehicle market penetration have not been changed in any of the three scenarios. Similarly, transportation energy use includes electricity generation losses.

We wish to emphasize that, in our judgment, the reductions in carbon emissions described in these scenarios are unlikely to be achieved by advances in technology alone, in the absence of meaningful additional policy measures to insure that cost-effective and near cost-effective technologies to improve energy efficiency and to expand the production of biomass fuels are in fact implemented. This is not only our conclusion. The 1995 Asilomar Conference on Energy and Sustainable Transportation, organized by the National Research Council (NRC), Transportation Research Board's Committees on Energy and Alternative Fuels, addressed the question, "Is technology enough to achieve sustainable transportation?" The conference's consensus, to be published in a forthcoming volume of proceedings, was that technologies capable of creating a sustainable transport system could be developed over a reasonable time period but that the marketplace on its own would be unlikely to adopt such technologies in the absence of specific policy measures to make it happen (McNutt et al., 1997). Because of the inertia inherent in the nation's transportation system, and because reducing greenhouse gas emissions is a public good, meaningful policy action is likely to be essential to achieving the carbon emissions reductions described in these scenarios.

We also believe that research and development of low-carbon emission technologies will have to be expanded to achieve the results of the efficiency and high-efficiency scenarios. Support for this view can be found in the NRC's just-published review (NRC, 1997) of the research program of the PNGV, the most significant national effort to advance technology to improve transportation energy efficiency. The views of the standing committee charged with reviewing the progress of the program are unambiguous:

> "The PNGV is experiencing severe funding and resource allocation problems that will preclude the program from achieving its objectives on its present schedule if they are not resolved expeditiously."

The panel comments on the serious underfunding of PNGV in at least nine different places in its report. In Table H-1, summarizing its assessment of the status and prospects for the key PNGV technologies, all technologies save fuel cells were categorized as having a basic need for additional resources. Noting that PNGV has been unresponsive in providing the committee with estimates of the funding that would be required, the committee notes that the industry consortium of the PNGV stated that it would like to see government funds available to PNGV doubled (NRC, 1997, p. 107). Elsewhere, the committee notes that funding for ultracapacitor research would have to be increased by at least ten times for a period of 10 to 15 years in order to catch up with the status of battery research with respect to PNGV goals. While the technological progress assumed in our efficiency case does not require that PNGV goals are attained, continued advances by industry and government R&D programs will be essential. PNGV, of course, addresses only light-duty vehicles. R&D support for low-greenhouse gas technologies for other modes is even more modest. In the view of the transportation sector analytical team, substantial additional funding for R&D will be required, perhaps two to ten times what is presently being spent, depending on the area of investigation.

5.2 PROVEN AND ADVANCED TECHNOLOGIES

Despite the fact that the fuel economies of successive model years of U.S. new cars and light trucks have been essentially constant for the past decade (Heavenrich and Hellman, 1996), technologies positively affecting vehicle efficiency have continually entered the fleet. These include fuel injection, 4-valve per cylinder engines, 4-speed electronically controlled automatic transmissions with lockup, growing use of lightweight materials and structural redesign for weight reduction, tires with lower rolling resistance, and improved aerodynamics. Efficiency improvements offered by these technologies have been counteracted, however, by increased acceleration performance and top speed; weight increases due to increased body stiffness and more power and safety equipment (e.g., air bags); and other factors. In other words, auto makers and purchasers have been willing to trade off fuel economy for competing vehicle amenities such as weight and power.

There is wide agreement that new efficiency technologies will continue to enter the fleet, and that technologies recently entered will gain market share. Table E.1 in Appendix E lists those technologies that appear in the NEMS data base and are expected to either gain market share or enter the market during the next decade or so. With a few exceptions, these are proven technologies whose costs and impact on efficiency can be reliably specified. The most important of these technologies, from the standpoint of their potential impact on fleet fuel efficiency during the next few decades, are described briefly below. Documentation for costs and projected fuel efficiency improvements for these and the other technologies in the NEMS data base is contained in Energy and Environmental Analysis, Inc. (1994).

5.2.1 Material Substitution

Weight reduction has been a key factor in the U.S. automobile fleet's fuel economy improvement since the early 1970s, and will likely play an important role in future improvements. Past weight reductions involved a combination of a widespread conversion to front-wheel drive, which eliminated the drive shaft and rear axle and allowed important packaging gains; a significant downsizing of the fleet, made possible by changing consumer demands; the shift to unit body construction from a chassis on frame structure; and material substitution, largely from plain carbon steel to high strength low alloy (HSLA) steels, but also including shifts to plastic parts and some aluminum as well. Recently, structural redesign using supercomputers has allowed significant weight savings. However, much of these savings have been taken back by increases in body rigidity, which enhances ride quality and safety, as well as the addition of safety and power equipment. Accordingly, the average weight of the fleet has begun to increase.

Despite past improvements, there remain substantive possibilities for large weight reductions without sacrificing vehicle interior space or safety. The Office of Technology Assessment (U.S. Congress, OTA, 1995)[2] identified an array of weight reduction scenarios including the following: a "clean sheet" design using advanced steel alloys that might achieve greater than a 10% weight reduction in a mid-sized auto; all-aluminum vehicles using successively more optimized designs achieving up to a 30% reduction; and a technically-optimistic design using polymer composites achieving a 35-40% reduction (though OTA considered this last scenario to be quite uncertain from a commercial standpoint because it requires breakthroughs in manufacturing technology).

Material substitution is treated in a series of steps in the NEMS model, with each step representing a 5% weight reduction relative to the baseline. The first step (now complete in the current new car fleet) represents increased use of HSLA, while the next four steps represent increasing use of plastics and aluminum over time, to achieve a total reduction of 20% relative to a modern 1990 vehicle (more with older non-unit body designs).

5.2.2 Aerodynamic Drag Reduction

Improvements in vehicle aerodynamics have been an important part of the overall fuel economy improvement of the U.S. light-duty vehicle fleet, with average drag coefficients (C_ds) being reduced from 0.45-0.50 in 1979/1980 to between 0.30 and 0.35 today, with some models in the 0.27-0.29 range. These reductions are important to vehicle fuel economy because a 10% reduction in C_d typically will yield a 2.0-2.5% increase in fuel economy at constant performance.

Prototypes with extraordinarily low C_ds (e.g., 0.18 for the Chevrolet Citation IV and 0.15 for the Ford Probe IV ("Going with the Wind," 1984)) have been shown, and the General Motors EV1 electric car attains a C_d of 0.19. There is a strong consensus among auto makers, however, that mass market vehicles will likely be limited to C_ds of about 0.25 because of limits on the practical slope of windshields, need for cargo space (low C_ds require tapered rear ends), and other factors, including customer design preferences. Further, reductions in C_ds for light trucks are limited by factors such as need for high ground clearance and large tires, open beds in pickup trucks, and so forth. Also, the short length of subcompact autos limits the degree to which their C_d can be reduced.

In NEMS, aerodynamic drag reduction is also implemented in a series of steps starting from a 1990 C_d baseline of 0.37, with each step representing a 10% reduction over the previous level (i.e., to 0.33, 0.30, 0.27, and 0.245, respectively).

5.2.3 Improved Automatic Transmissions

A range of potential improvements to automatic transmissions can offer fuel economy benefits of up to about 6% in automobiles. Key areas of improvement are design changes that reduce hydraulic losses in the torque converter and transmissions with added numbers of gears, with continually variable transmissions possible.

Five-speed automatic transmissions were introduced in Japan and Europe a few years ago and have recently been introduced to the United States in a few luxury models. Nissan and Mercedes have experienced fuel economy gains over a 4-speed automatic in the 2-3 MPG range (Hattori et al., 1990). A number of continuously variable transmissions (CVTs) have been tested with widely varying results, and Suburu sells a small car with a CVT in the U.S. market. OTA estimates that a CVT should be capable of achieving approximately a 6% fuel economy increase over a 4-speed automatic.

Electronic transmission control of both conventional automatic transmissions and CVTs will add some benefits over the older mechanical controls. First generation controls selected only the shift points and provided about 0.5% benefit in fuel economy, and such controls were in most transmissions by 1995. More advanced second generation controls have appeared, and they interact with the engine control to optimally select torque converter lock-up and shift points while also determining engine calibration. Such controls provide 1.5% benefit over mechanical controls.

5.2.4 Engine Friction Reduction

Reducing mechanical friction is an ongoing process in engine development, and steady reductions in friction have occurred as engine designers continually modify existing engines and introduce new engine families. There is substantial potential for fuel economy gains as existing friction reduction improvements are rolled into the fleet. Primary areas for further improvement are:

- Piston and connecting rod weight reduction using lightweight materials,
- Lightweight valves and valve springs,
- Use of two rings instead of three,
- Improved oil pumps,
- Improved lubricants,
- Low friction crankcase seals, and
- Roller cam followers.

Only roller cam followers and two-ring pistons are discrete technologies, with specific benefits of 2% in fuel economy, while other benefits are based on design evolution.

Fuel economy improvements of as much as 4.5% (compared to current engines) should be available using the full range of evolutionary technologies. The NEMS model has separate representation of roller cams, while all other technologies are modeled as engine friction reduction in discrete steps of 1.5% benefit in fuel economy, with steps in the order of increasing cost and complexity.

5.2.5 Variable Valve Timing

In conventional engines, the timing and extent of opening of the intake and exhaust valves are fixed, and are compromises between the very different needs of high and low power settings. Variable valve control allows substantial efficiency improvement; for example, closing the intake valves early can substitute for throttling to reduce air intake, thus reducing pumping losses at low load. Also, variable valve control boosts engine power, allowing engine downsizing while maintaining power levels.

Honda uses a system called VTEC that controls both lift and timing of intake and exhaust valves. VTEC is not a fully variable system, offering only two settings for valve timing and lift, but it still obtains an 8% fuel economy improvement at constant performance. It has been used in the U.S. market both for boosting power (Acura NSX, Prelude VTEC) and improving fuel economy (Civic VX).

Although VTEC was introduced to the U.S. market in 1991 (in the NSX), neither VTEC nor competing systems (Mitsubishi uses a system, MIIVEC, that combines valve control with cylinder shutdown at low loads) have gained significant market share since then. The major concerns are cost and complexity. Second generation VVT systems that offer wider control of lift and timing are expected to increase fuel economy benefits at constant performance to 10%.

5.2.6 Lean-Burn Engines

Lean-burn engines reduce engine power by reducing fuel flow without throttling back airflow, thus increasing the air/fuel ratio; in contrast, conventional engines maintain air/fuel ratios at or below "stoichiometric" (i.e., the ratio – about 14.6:1 – where there is just enough air to fully combust the fuel). Aside from the reduced pumping loss obtained by foregoing throttling, engine thermal efficiency is increased and hydrocarbon and carbon monoxide emissions are reduced. The primary challenges facing lean-burn engines are difficulties in maintaining stable combustion at high air/fuel ratios and the need to develop new NO_X catalysts that will work in an oxygen-rich exhaust environment. The former challenge generally is handled by designing the cylinder/piston/valves/fuel injector system and operation in such a way as to stratify the fuel charge so the region around the spark plug has a richer fuel mixture than in the rest of the combustion chamber and ignites readily. An alternative method is to use high swirl combustion chambers that promote combustion. For the emissions challenge, most automobile manufacturers are working to develop "lean NO_X catalysts," and, as discussed below, both Toyota and Mitsubishi have sold vehicles that combine lean operation and new NO_X catalyst technology since the early 1990s in Japan.

Low cost lean-burn systems that do not need "direct injection" of fuel into the cylinder head can provide up to a 10% benefit in fuel economy by utilizing advanced cylinder head designs and lean air-fuel sensors.

5.2.7 Advanced Tires

Rolling resistance accounts for approximately a third of the loads on an automobile during the EPA test procedure. The magnitude of this resistance is approximately linearly related to the rolling resistance coefficient of the vehicle's tires, so reducing this coefficient through changes in tread design, tire materials, and tire structure will have a significant positive impact on fuel economy.

Tire design and materials have improved steadily throughout the years, with the switch to radials from bias-ply tires beginning in the late 1970s, then the shift to second generation radials beginning in the mid-1980s each achieving about a 20-25% reduction in rolling resistance and a 3-4% improvement in fuel economy.

Additional improvements have recently been introduced by Michelin and other companies and are beginning to penetrate the fleet. Use of these and other, further-improved designs can yield about a 25% reduction in rolling resistance by 2005, with 5% improvement in fuel economy resulting; an additional 3% fuel economy improvement may be possible by 2015 (Hattori et al., 1990). Some of these gains are likely to be offset by manufacturer design decisions that increase tire traction and durability, so that only about half the potential fuel economy gains are likely to be realized. The NEMS model has the improvements occurring in four discrete steps over time to achieve a total 4% benefit in fuel economy.

Aside from these proven technologies, there are a few additional technologies that are not expected to enter the fleet in commercially significant amounts before 2010 under the business-as-usual case assumptions, but that have the potential to impact fleet fuel economy in this time frame if there are appropriate incentives. These are:

- Advanced drag reduction (to a C_d of 0.22 for mid-sized vehicles),
- Hybrid-electric power trains,
- Direct injection stratified charge (DISC) gasoline engines,
- Direct injection (DI) diesel engines, and
- Proton exchange membrane (PEM) fuel cell power trains.

All but the PEM fuel cell power trains are considered likely to be introduced into the U.S. in small numbers before 2010 (e.g., in limited edition or luxury models). In fact, Volkswagen has already introduced DI diesel engines into the U.S. market as options in its Passat, Jetta, and Golf models. DI diesels cannot meet current NOx standards for gasoline-fueled automobiles. At this time, diesels have an exemption to U.S. rules on NOx emissions; however, this exemption is unlikely to stand if large numbers of diesels are sold in the U.S. market. Similarly, DISC engines have been introduced into the Japanese fleet by Toyota and Mitsubishi, but their high cost and U.S. emissions requirements should keep them out of the U.S. fleet for the immediate future – except perhaps in very limited numbers. As discussed below, however, these technologies could make an impact on U.S. fleet fuel economy before 2010 either in the efficiency scenario, which postulates both increased R&D spending and increased market or regulatory incentives for fuel economy, or in our high-efficiency/low-carbon scenario that postulates better-than-expected luck in technology development.

5.2.8 Advanced Drag Reduction

In our view, significant market pressure on fuel economy could reduce C_d values a bit further than projected by the auto makers. Some existing vehicle designs that have attained lower C_ds without some of the design compromises of the prototypes noted above indicate that a C_d of 0.22 should be practical for a mid-size car without requiring wheel skirts or a sharply tapered rear end.[3] This value has been adopted as successfully entering the mass market automobile fleet in both the efficiency and high-efficiency/low-carbon scenarios, and is modeled as an additional 10% reduction in drag over the lowest C_d value in NEMS of 0.245.

5.2.9 Hybrid-Electric Power Trains

Hybrid-electric power trains combine two energy sources with an electric drivetrain, with one or both sources providing electricity to the electric motor. Although many configurations are possible, all have some form of energy storage (battery, flywheel, ultracapacitor, etc.). Hybrids offer a theoretical efficiency advantage over conventional internal combustion engine (ICE) drivetrains for the following reasons:

- They offer the potential to recapture some of the vehicle's potential energy that is normally lost (as heat) when the vehicle is braked. In a hybrid, the electric drive motor can be operated in generator mode to brake the vehicle; the electric energy produced is stored in the battery or other storage device.
- The hybrid drivetrain allows the vehicle powerplant to be smaller and to operate more efficiently than the powerplant in a conventional drivetrain. In a conventional drivetrain, the engine is sized for the maximum load (usually short-term rapid acceleration) and can produce many times the power it uses during the great majority of its operation. For example, during idle, low speed cruise, or deceleration, the powerplant may be operating below 10% of its

maximum power capability, and most engines (especially gasoline engines) are very inefficient at such lower power levels. Because the storage device can absorb any excess power (over that needed to operate the vehicle) produced by the engine, the engine can continue to operate at an efficient power level even when the vehicle loads are low. Also, in a hybrid, the storage device can provide part of the power for maximum acceleration, allowing the hybrid powerplant to be sized for average power requirements or for power requirements in operations where the battery can't help (e.g., during sustained hill-climbing), which are generally lower than acceleration loads – so the hybrid's engine can be smaller.

The net energy gains from the regenerative braking, smaller and lighter powerplant, and improved powerplant cycle efficiency are counteracted by losses in the electrical components (storage device, generator, motor/controller) and their added weight (in particular, weight of the storage device and electric motor). The wide variety of hybrid configurations and component designs, the relatively early stage of development of hybrid powertrain systems, and the ongoing redesign of hybrid powertrain components to satisfy the unique requirements of hybrid operation has yielded a wide range of estimates of the potential efficiency benefits of shifting to hybrid drivetrains. Further, ongoing changes in engine design for conventional drivetrains shift the relative value of hybridization, with reduction in pumping losses achieved by variable valve control, for example, reducing the benefit of hybridization because these are the same losses hybridization is designed to counter. The OTA has estimated that a battery/ICE hybrid can achieve about a 25-35% gain over a conventional drive vehicle with the same type of powerplant, assuming what it considered optimistic values for the efficiencies of the battery and electric motor (U.S. Congress, OTA, 1995). Current examples of operating hybrids that satisfy normal vehicle safety and performances requirements[4] have not achieved efficiency improvements this high (U.S. Congress, OTA, 1995). On the other hand, the Department of Energy's (DOE's) goal for its hybrid drivetrain R&D program is a doubling of fuel economy, and theoretical analyses of hybrid configurations using simulation models have projected gains ranging as high as the DOE goal (Burke, 1995; Ross, 1996). In our view, gains this high are unlikely without sacrificing some aspects of performance or operational flexibility. On the other hand, there are active R&D efforts on hybrid components such as ultracapacitors and high-efficiency electric motors that, if successful, could raise the efficiency advantage of hybridization to somewhat higher levels than OTA projects. The efficiency case conforms approximately to the OTA projections; the high-efficiency/low-carbon case assumes exceptional success at improving drivetrain components and reducing costs. This translates to a 28% fuel economy benefit over a 1995 conventional gasoline-fueled car, and a 10% benefit over a DI diesel vehicle for the efficiency case; in the high-efficiency/low-carbon case, the assumed gains are 43% and 23%, respectively.

The primary barriers to successful commercialization of hybrid-electric vehicles are the current high costs of electric motors, controllers, and batteries, and the need for additional progress in reducing the specific power and increasing the efficiency of these electrical components. In particular, there is an urgent need for reliable high-efficiency, high specific power batteries. There recently has been progress on such batteries, but considerable work remains. In addition, there are relatively few suitable engines in the right size category (one liter or so) for hybrids, since automotive engines typically are sized to meet the higher power requirements of conventional drivetrains.

5.2.10 Direct Injection Stratified Charge (DISC) Gasoline Engines

Conventional spark ignition (gasoline) engines are inefficient at part load in large part because they reduce power by throttling back on their air supply, creating large drag losses (so-called "pumping losses") in the stream of intake air. Direct injection stratified charge engines do not throttle intake air; instead, they reduce only fuel flow at part load, operating at fuel/air ratios as low as 1:50. They manage this by injecting fuel directly into each cylinder at high pressures (700 psi or higher compared to 50 psi in a conventional fuel injection system (Markus, 1997)) in such a way that the fuel/air mixture is stratified (thus, "stratified charge"), with high fuel concentrations near the spark plug so as to maintain stable combustion. The combination of zero throttling losses, low fuel use at light loads because of the very lean fuel mixture, and some added benefits of direct injection – particularly, more precise control of combustion and fewer problems such as fuel condensation on intake-port walls – yields substantial fuel efficiency improvements rivaling those of DI diesels.

Concerns with DISC engines include problems with increased NO_X emissions because normal reduction catalysts will not operate in the oxygen-rich exhaust environment of a lean-burn engine; the expense and durability of the fuel injectors, which have to operate at very high pressures ranging up to 2000 psi; and the need for extremely precise control of combustion to maintain smooth performance from the engine as it shifts back and forth between lean to stoichiometric operation.

Both Toyota and Mitsubishi have introducing DISC engines into their fleets in Japan, Mitsubishi with a 1.8 liter, 148 hp engine in its Galant sedan and Legnum wagon, Toyota with a 2.0 liter, 143 hp engine in its Carina sedan (Markus, 1997). Both companies use catalysts to reduce NO_X emissions: Mitsubishi's is a true lean-NO_X catalyst that reacts hydrocarbons with NO_X to form nitrogen, oxygen, water, and carbon dioxide; Toyota's system stores NO_X and reduces it to nitrogen during high power operation when the engine uses a stoichiometric (no excess air) air/fuel mixture (Markus, 1997). Neither system is believed ready to meet U.S. emissions requirements, especially for catalyst longevity. The Toyota system would likely experience difficulties with high levels of sulfur in U.S. fuels, which can poison the catalyst material.

Available data suggest that Toyota's DISC engine provides a 25% fuel economy benefit in the Japanese 10-mode cycle, which could translate to an 18% benefit in the U.S. FTP if emissions problems are solved. This benefit has been used in the efficiency case; in the high-efficiency/low-carbon case, a benefit of 23% is assumed.

5.2.11 Turbocharged Direct Injection (TDI) Diesel Engines[5]

Until recently, all diesel powertrains used in light-duty vehicles in the United States were indirect injection diesels (IDI). In an IDI diesel, fuel is sprayed into a prechamber, mixed with air, and partially burned before the charge is passed into a main combustion chamber where the combustion continues. This design was desirable for automobiles because it yields smoother combustion with less noise and lower NO_X emissions than direct injection designs. These advantages are purchased at the expense of some efficiency losses from heat transfer from the prechamber and pressure losses as the partially burned gases flow through the passages between the prechamber and main combustion chamber.

Advances in fuel injection technology and combustion chamber design, coupled with turbocharging and intercooling, have allowed direct injection diesels to attain smoothness and noise levels comparable to IDI diesels with low NO_X emissions and high specific power (power/weight) levels, approaching that of naturally aspirated 4-valve per cylinder gasoline engines. The best 4-valve turbocharged DI diesels can attain fuel economy improvements of 40% or more over current 2-valve per cylinder engines, though conversion to gasoline equivalent fuel economy yields closer to a 30% gain (diesel fuel is a more energy-dense fuel than gasoline). The 40% value has been used in our analysis, but it assumes that lean-NO_X catalysts will be successfully adapted to diesels to meet NO_X standards. Catalyst researchers generally are considerably less optimistic about success for diesels than they are for gasoline-fueled vehicles.

As noted above, Volkswagen has introduced DI diesels into the U.S. fleet in its Golf, Jetta, and Passat models. These engines are 1.9 liter and produce 105 horsepower. Audi produces a larger 2.5 liter engine for its European models.

5.2.12 Proton Exchange Membrane (PEM) Fuel Cell Powertrains

Fuel cells are electrochemical devices that convert the chemical energy in fuels to electrical energy directly, without combustion. This process avoids the thermodynamic limitations imposed by the Carnot cycle, and fuel cells theoretically can have efficiencies of 90% or greater. With hydrogen as a fuel, fuel cells have emissions only of water; with fuels such as methanol or hydrocarbons, reforming to obtain hydrogen will produce small quantities of carbon monoxide and other pollutants as byproducts and larger quantities of carbon dioxide.

For the immediate future, PEM fuel cells appear to be the clear choice among alternative fuel cell technologies for light-duty vehicle applications because they operate at moderate temperatures (20-120 degrees C) and developers have been able to rapidly improve their power density (from .085 kW/liter in 1989 to about 1 kW/L today) and decrease their costs (platinum loadings, a major cost factor, have been reduced from about 4 mg/cm^2 in 1990 to current levels of about 0.15 mg/cm^2) (Oei, 1997).

Despite rapid progress, fuel cells must overcome major hurdles before they can succeed commercially in the light-duty market. Costs must be sharply reduced. Even with mass production, PEM fuel cells would cost at least $200/kW to manufacture with today's production technology and cell designs – nearly ten times the cost of ICE engines (Oei, 1997), disregarding the additional cost of needed hydrogen storage or reformers.[6]

Key needs are development of low-cost membranes, size and cost reduction of hydrogen reformers or onboard storage, and improvement of "balance of plant." Also, there are several "engineering" issues that will have to be dealt with once stack design has gotten to the point where serious vehicle design is contemplated – for example, cooling (the low temperature operation of fuel cells means that the heat being rejected is very low grade heat, requiring lots of air movement or large radiator surface areas, neither very appealing to vehicle designers (Borroni-Bird, 1997)) and prevention of freezing in cold weather.

On-board fuel storage represents a significant barrier because hydrogen's energy density is very low,[7] and the easiest fuel to reform into hydrogen onboard the vehicle, methanol, has no significant supply infrastructure. Chrysler in partnership with DOE recently announced significant progress towards onboard production of hydrogen from gasoline, which would solve the supply infrastructure problem and allow much easier fuel storage than hydrogen. Not surprisingly, however, the selection of gasoline as the preferred "hydrogen carrier" for fuel cells is by no means an easy call. For example, gasoline's availability and easier fuel storage must be traded off against the cost and space occupied by the reformer (Jost, 1997).[8] Toyota has claimed a substantial improvement in hydrogen storage technology using an advanced metal hydride adsorbent that matches the energy density of liquefied hydrogen storage with only 10 atmospheres of pressure required (Yamaguchi, 1997). Presumably, however, this type of storage would be extremely heavy. Other options being pursued by various researchers include direct methanol fuel cells, which preclude the need for a reformer, and the use of ethanol in place of methanol or gasoline as a hydrogen source. The latter option is especially attractive if the ethanol can be produced from cellulosic materials, because the effect on reducing greenhouse gas emissions is particularly large for this technology.

We expect the rate of progress and probability of commercialization of fuel cell powertrains to be sensitive to the level of R&D funding and market pressures to improve overall vehicle fuel economy. Progress has in fact been rapid, as shown by the improvements in power density discussed above. Ford, GM, and Chrysler are all pursuing fuel cell vehicle R&D, as are Japanese and European companies, with Toyota's and Mercedes Benz's programs being the most visible. A Canadian company, Ballard, appears to be in a leading position in PEM fuel cell R&D, and has supplied systems to most of the vehicle R&D programs. Given current funding levels and the market's lack of pressure on fuel economy levels as well as the large amount of development work that remains to be done, however, introduction of fuel cells into mass market vehicles appears likely to be beyond the 2010 time frame, and the base scenario adheres to this projection. This, in fact, was the conclusion of the NRC's advisory panel overseeing the PNGV program (NRC, 1997, Table H-1). On the other hand, increased funding and market pressure and/or particularly fortuitous progress in the ongoing R&D program might move the date of introduction forward. Further, the newness of the technology and the dependence of the basic fuel cell stack costs on manufacturing design leaves open the potential that the eventual cost of the fuel cell system might be somewhat lower than competing ICE drivetrains; this depends on substantial cost reduction over a range of technologies, because the costs of hydrogen storage or reforming, the electric motor, and even the battery that is likely to be necessary for startup power, all play a significant role in total system costs.

The efficiency case assumes that fuel cells will not be introduced in mass market vehicles before 2010; we note that the major auto makers are not projecting a pre-2010 commercial introduction of fuel cell vehicles even assuming a high level of success in their development programs. The PNGV program envisions that the earliest fuel cells will use a reformer to produce hydrogen from gasoline. We assume that fuel cells in conjunction with a gasoline reformer will be about 70% more efficient than current gasoline engines, but only slightly more efficient than a diesel hybrid drivetrain. The high-efficiency/low-carbon case assumes introduction of commercial gasoline fuel cell vehicles by 2007. Although ethanol from cellulosic material would make an excellent fuel for the fuel cell hybrid and would result in further reductions in greenhouse emissions, we assume the first fuel cell vehicles will use widely-available gasoline.

5.2.13 Fuel Cells in Heavy Trucks and Locomotives

In many ways, fuel cell propulsion may be attractive for large transportation vehicles, such as locomotives or ships, before it is ready for use in light-duty vehicles. Use of fuel cells in heavy trucks will require a breakthrough in hydrogen production, distribution, or on-board storage, or else a breakthrough in reforming technology before it will be competitive with the diesel engine. The drive-cycle thermal efficiency of current heavy-duty diesel truck drivetrains is in the range of 35% to 40%. The drive-cycle thermal efficiency of current methanol steam-reforming fuel cell drivetrains (including electric motor/controller and battery) is also 35% to 40%. Thus, there is likely to be little incentive for heavy trucks to switch to fuel cells until hydrogen fuel cells, with drivetrain efficiencies in the range of 45% to 50%, become available.

Fuel cells may succeed in the locomotive market first because, (1) fuel costs are more important to rail carriers than to truckers, (2) locomotives already use electric traction drive and, (3) fuel cells of the size necessary for locomotive powerplant output (4000 HP) are already commercially viable in stationary powerplant applications. Therefore, we consider the use of fuel cells in locomotives in the high-efficiency/low-carbon scenario. Fuel cells may also have applicability to marine vessels, again because of their size. We do not introduce marine fuel cell applications in the high-efficiency/low-carbon technology scenario, simply because we are not aware of suitable applicability studies. We believe that analysis of the potential for fuel cell technology in heavier transportation vehicles would likely reveal additional promising applications. Thus, the locomotive fuel cell analysis is intended more to be indicative of potential large-scale fuel cell applications in transportation than a reflection of our judgment of the true potential market.

Locomotives can be broadly classified into two types: local service and line haul. Local service locomotives are primarily older line-haul locomotives that are low powered (2000-3000 HP), and are typically utilized in light load applications. Local service locomotives consume about 120,000 gallons/year of fuel per locomotive. Line-haul locomotives are more powerful (4000 HP) and consume 375,000 gallons/yr of fuel per locomotive. Both types spend considerable amounts of time at idle, over 70% of the time for local service locomotives and over 50% of the time for line-haul. Idle fuel consumption accounts for 38% of fuel consumed in local service locomotives, and only 6.3% of fuel consumed for line-haul locomotives (CARB, 1991; CARB, 1992).

Locomotives have very long useful lives and the engines are rebuilt several times. The diesel engine alone costs about $400,000, but a complete rebuild costs only about $100,000 to $150,000. Engines are typically rebuilt every eight years, and the entire locomotive is rebuilt every 24 years and/or moved to local service at that point. Hence, a useful life calculation of 24 years may be reasonable in terms of a replacement cycle.

A fuel cell based locomotive could utilize methanol, ethanol, or liquefied natural gas (LNG) and could be of the PEM type being considered for cars or the Phosphoric Acid type used for power generation. It is believed that for high power applications, the Phosphoric Acid Fuel Cell is in a relatively greater state of maturity. Several large units are currently operating as prototypes for power generation. Estimates of future fuel cell costs are highly uncertain, but megawatt size Phosphoric Acid units could be manufactured at low volumes for approximately $1000/kW in the near future, and perhaps at $400-500 per kilowatt in ten years. At this cost, a typical locomotive unit of 3000 kW would cost $1.2 to $1.5 million in 2007 reflecting a cost premium of $800,000 to $1.1 million over a diesel engine powered locomotive. It is also possible that "rebuilds" would not be required every eight years so that net cost differences may be smaller over the lifetime of the locomotive. Also, developers of PEM cells for highway vehicles are aiming at sharply lower costs, in the range of $50 per kilowatt (for the fuel cell only) or lower; although the size, duty cycle, and manufacturing volume of locomotive and automotive power plants are clearly very different, presumably a portion of any cost reductions achieved in automotive fuel cells would be applicable to fuel cells designed for locomotives.

The average efficiency of the fuel cell over the duty cycle would be 1.6 to 1.7 times as high as the diesel engine (whose cycle average efficiency excluding idle is about 35%). Fuel savings of 40% are possible, which is approximately 150,000 gallons/year for a line-haul locomotive. Hence fuel savings alone could pay for the capital cost increases over about eight years, making the technology reasonably cost-effective in the context of a 24-year useful life. Of course, major uncertainties exist in the actual cost of the fuel cell for a 3000 kW unit, the life of the fuel cell, and the maintenance requirements relative to a diesel engine.

If successful, fuel cell locomotives could have a 5 to 6% market share by 2010, and 16 to 18% by 2015, for the total fleet. In the high-efficiency/low-carbon scenario, we assume a 5% share in 2010 and 20% by 2015. We further assume use of cellulosic ethanol, although methanol and LNG would also be likely candidates.

5.2.14 Costs and Timing of Technology

As part of the OTA study, the cost of all the above-described automotive technologies was derived on the basis of near-term estimates, though at high production volume.. One possible area for improvement in costs is the effect of research and additional learning to provide an "experience" based cost reduction. Lipman and Sperling (1997) have analyzed cost reductions based on cumulative total production, and concluded that many new technologies experience a 20 to 35% cost reduction for every order of magnitude increase in cumulative production (i.e., the cost decline function is linear with respect to the logarithm of cumulative units produced). If these new technologies are manufactured at typical automotive volumes from their introduction, then an order of magnitude increase in cumulative production will occur over a span of five to seven years with sales growth over the period. The next order of magnitude increase in cumulative production will take much longer unless the technology essentially increases market share to 100% over the next decade. We have utilized the data from the Lipman and Sperling paper to conclude that a 30% cost reduction over the 1997-2005 period is possible relative to the costs derived for OTA.

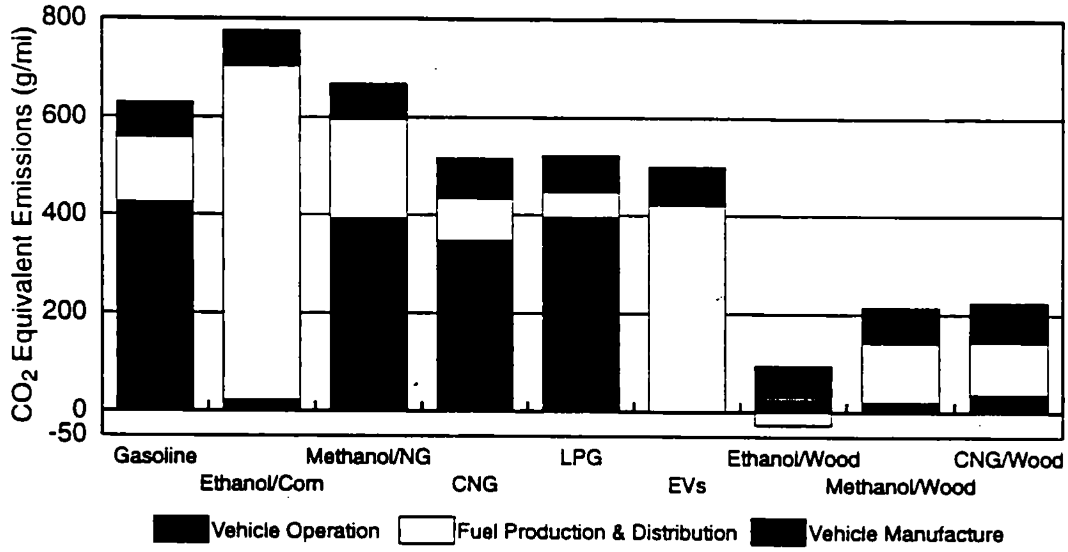
A second factor is the timing of technology introduction. The contrast here is between new technology introduction in a business-as-usual scenario relative to one where both business and government invest in research and development at rates consistent with an accelerated PNGV, coupled with changes in market preferences for fuel economy driven also by changes in government policy (e.g., new fuel economy standards, high motor fuel taxes, etc.). The resulting reduction in lead time is assumed to be 30% relative to the earliest introduction dates forecast by OTA, starting from 1997. In other words, a technology forecast by OTA to be commercialized in 2010 (13 years from 1997) would be expected to arrive in 2006 (1996 + [13*0.7]) under the regime of increased R&D spending and market changes. This factor has been incorporated for all post-2005 technologies defined in NEMS or added to the NEMS technology list for the efficiency and high-efficiency/low-carbon cases.

5.2.15 Alternative Transportation Fuels

Alternative Fuels derived from fossil energy sources have limited potential to reduce greenhouse gas emissions. The full fuel cycle greenhouse gas emissions of fossil fuels have been compared in detail by Delucchi (1991, Tables 9a-e), Wang (1996) and others. Several fossil fuel alternatives have somewhat lower CO_2 emissions than conventional or reformulated gasoline (RFG), most notably liquefied petroleum gases and natural gas, whether compressed (CNG) or liquefied (LNG). On the basis of emissions of CO_2 equivalent greenhouse gases per vehicle mile, CNG and LPG offer moderate reductions both for light (Figure 5.1) and heavy-duty (Figure 5.2) vehicles. Methanol from natural gas, while it is a relatively attractive alternative fuel for spark-ignited internal combustion engines, seems to offer no CO_2 reduction potential.

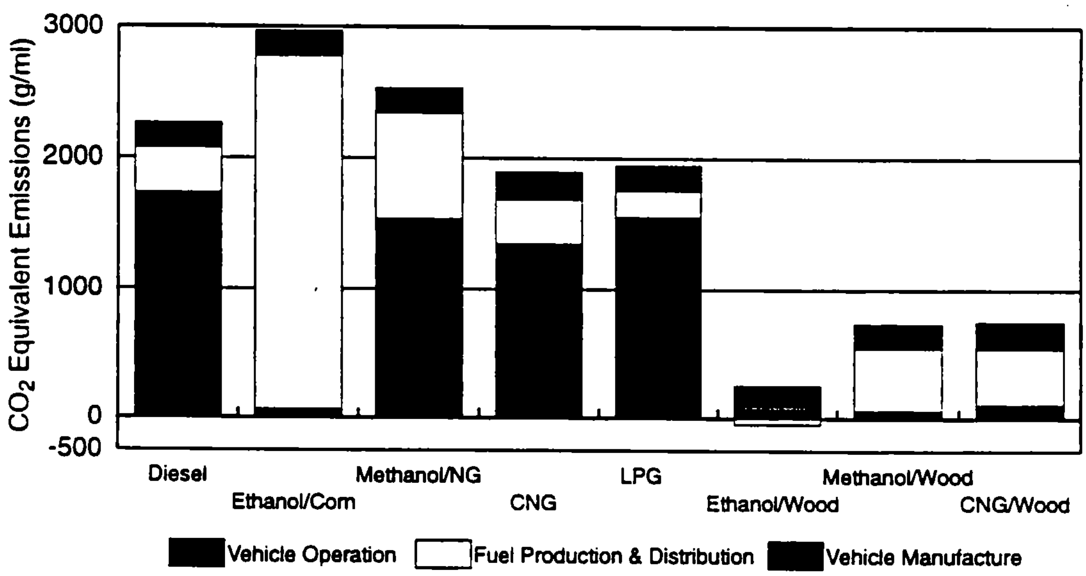
Battery-powered electric vehicles (EVs) can also lower greenhouse gas emissions, depending on the energy source used to produce the electricity stored in the vehicle's batteries. Electricity obtained from nuclear or solar power would very nearly eliminate greenhouse gas emissions. Use of nuclear power is unlikely, however, since nuclear power plants tend to operate at capacity at present and are not likely to supply a marginal increase in demand due to electric vehicle use. Electricity from current natural gas-fired plants would achieve roughly a one-third reduction, and electricity from advanced combined cycle natural gas generations could do even better. Estimating CO_2 emissions reductions from electric vehicles is highly dependent on assumptions about when vehicles will be recharged and how utilities will choose to operate different kinds of generating units. One such set of estimates, developed based on technologies and generation mixes projected for 2015, is shown in Figure 5.3. There are no CO_2 emissions from vehicle operation and emissions from vehicle manufacture are the same for all regions. Largely due to greater use of natural gas in advanced generating units, the south central and west regions are expected to produce the lowest greenhouse gas emissions for EVs operated there.

Figure 5.1 Fuel Cycle Greenhouse Gas Emissions for Light-Duty Vehicles



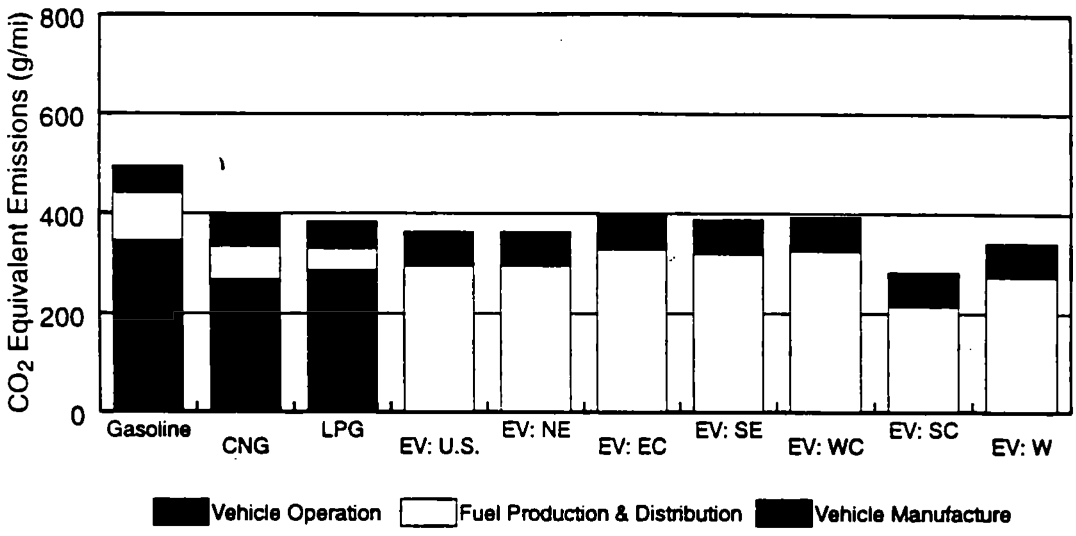
Source: Leiby et al., 1996, Table D-4

Figure 5.2 Fuel Cycle Greenhouse Gas Emissions for Heavy-Duty Vehicles



Source: Leiby et al., 1996, Table D-4

Figure 5.3 Projected Fuel Cycle Greenhouse Gas Emissions of Battery-Powered Electric Vehicles by Region in 2015



Source: Singh (1997)

The analyses in Chapters 6 and 7 indicate that there is considerable opportunity to reduce carbon emissions in the electric utility sector. A substantial shift towards lower-carbon electric generating facilities will increase the carbon-reducing benefits of electric vehicles. For example, large shifts away from coal and towards natural gas, especially with combined cycle technology, will tend to push the relatively high EV emissions in regions whose dominant fuel is now coal (Figure 5.3) down towards the lower emissions prevalent in areas with primarily gas-fired electricity (e.g. California).

The AEO97 reference case already projects large increases in the numbers of electric and natural gas vehicles on the road. Primarily as a result of zero emission vehicle (ZEV) regulations in California, AEO97 foresees annual sales of 75,000 battery electric cars and 150,000 battery electric light trucks in 2010. To this is added more than a quarter million hybrid electric vehicles. By 2010, the AEO97 reference case projects nearly 2 million battery-electric and over 2 million hybrid electric light-duty vehicles in operation. Given the recent relaxation of ZEV mandates in California, this projection now seems optimistic. The AEO97 reference case also projects compressed natural gas vehicle sales at 325,000 units in 2010 with a total on-road stock of 2.6 million light-duty vehicles. This is more than thirty times the 82,000 CNG vehicles estimated to be on the road today (EIA, 1996c, Table 1). We retain these alternative fuel vehicles in all three scenarios, but do not expand them.

Among the alternative transportation fuels under consideration, biomass fuels derived from wood appear to have the greatest potential to reduce greenhouse gas emissions. Whereas ethanol derived from corn may actually produce higher levels of CO_2 equivalent emissions than conventional gasoline (depending on the fuel used to power the distillation plant, and other factors), ethanol derived from cellulosic sources (wood, switchgrass, wood wastes, agricultural residues, municipal solid waste), can reduce carbon emissions by about 90% for both light-duty and heavy-duty vehicles (Figures 5.1 and 5.2). Cellulosic ethanol has the potential to be more effective than compressed synthetic natural gas derived from wood, partly because of the energy that must be used to compress methane for storage on board the vehicle, and partly because cellulosic ethanol production yields by-products that can be used to generate more electricity than is required to produce the ethanol (Delucchi, 1991, Table 9b; Wang, 1996).

Both battery electric vehicles and compressed natural gas vehicles, but especially battery-powered vehicles, are likely to cost more than conventional gasoline vehicles, will require more frequent refueling, and will have reduced range (Greene, 1994). It does not appear likely that most consumers will consider these drawbacks to be outweighed by the likely lower fuel costs for these vehicles. Thus, we expect these potential low CO_2 fuel technologies will not easily achieve the business-as-usual forecast market shares (of course, technological breakthroughs in batteries or gaseous fuel storage could make these vehicle technologies much more attractive). It is for these reasons that we focus below on the use of cellulosic ethanol as a transport fuel.

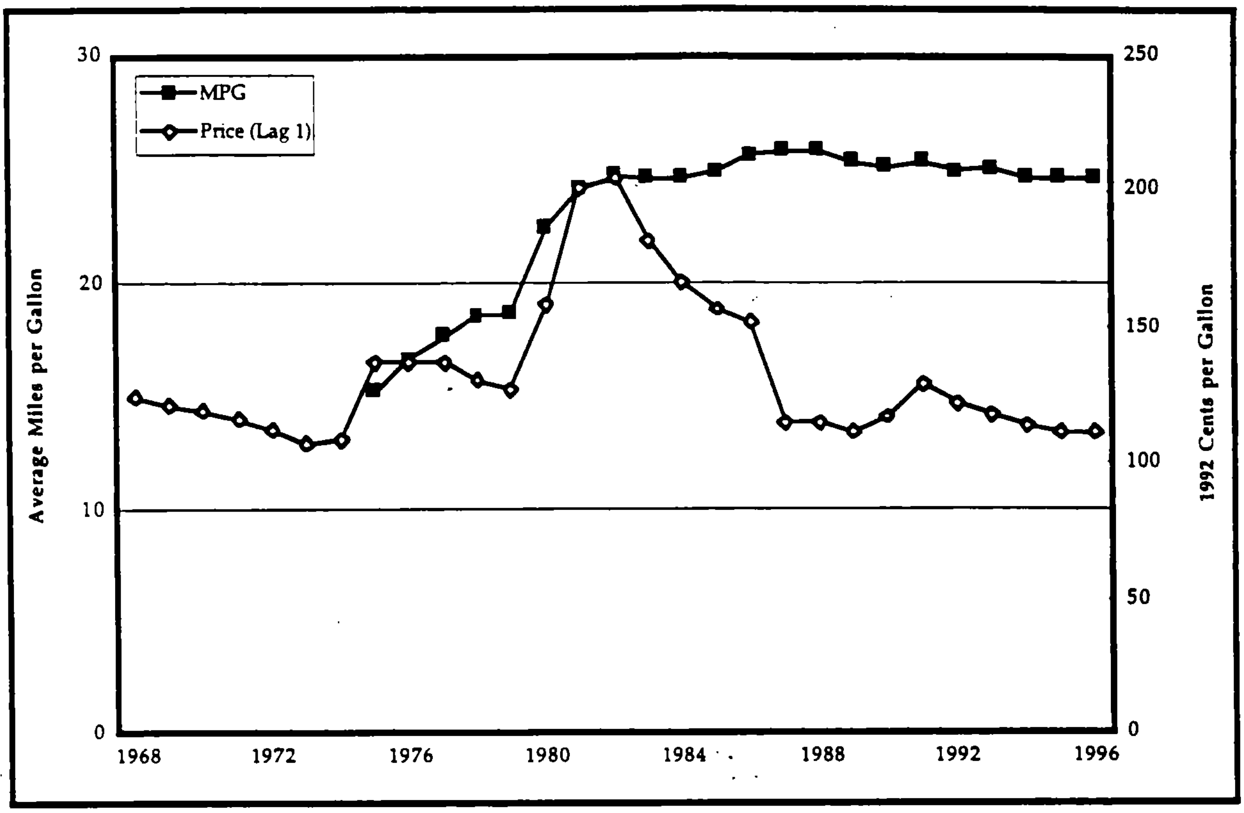
5.3 SCENARIOS FOR 2010

5.3.1 The Business-as-Usual Scenario for Transportation

The AEO97 reference case serves as the business-as-usual case, except for its forecast of increasing light-duty vehicle MPG through 2015. The EIA AEO97 reference case projects an increase in passenger car MPG from 27.5 in 1997 to 31.5 in 2010 and 32.6 in 2015. Light truck MPG is projected to increase from 20.5 to 22.9 MPG in 2010 and 24.2 MPG in 2015. We view this as inconsistent with the historical record, which appears to us to indicate that, without increasing fuel prices or a policy intervention such as fuel economy standards, MPG is not likely to increase. Thus, we incorporate zero MPG improvement after 1997 for light-duty vehicles into our business-as-usual case, reflecting the view that the current level of CAFE standards are and probably will remain a binding constraint on light-duty vehicle fuel economy throughout the business-as-usual forecast.

From 1982 to 1997, light-duty vehicle fuel economy remained essentially constant, as shown in Figure 5.4. Of course, motor fuel prices declined sharply at the beginning of the 1983-1997 period, but are at about the same levels today as they were in 1986, and as they were in the early 1970s prior to the first oil price shock. Given that the AEO97 oil price forecast projects no significant increase in oil or gasoline prices through 2015, it is reasonable to ask why fuel economy should increase. The EIA's view is that advances in motor vehicle technology will permit not only fuel economy but other vehicle attributes such as performance and weight to be increased at lower costs, resulting in greater consumer satisfaction. There is a very small increase in the price of gasoline through 2010, and this together with a slowing of income growth may allow the rate of technological advance to catch up with and pass the effect of consumer demand for larger, more powerful vehicles. Because a significant slate of cost-effective current and future fuel economy technologies are represented in the reference case input data, the model takes advantage of them even though fuel prices do not increase. NEMS would make greater use of the technologies if prices increased significantly, but the model is driven partly by technology availability and partly by changes in economic parameters. To some extent, the fuel economy benefits of these technologies are offset by a predicted increase in demand for performance. Nonetheless, a 5 MPG gain remains.

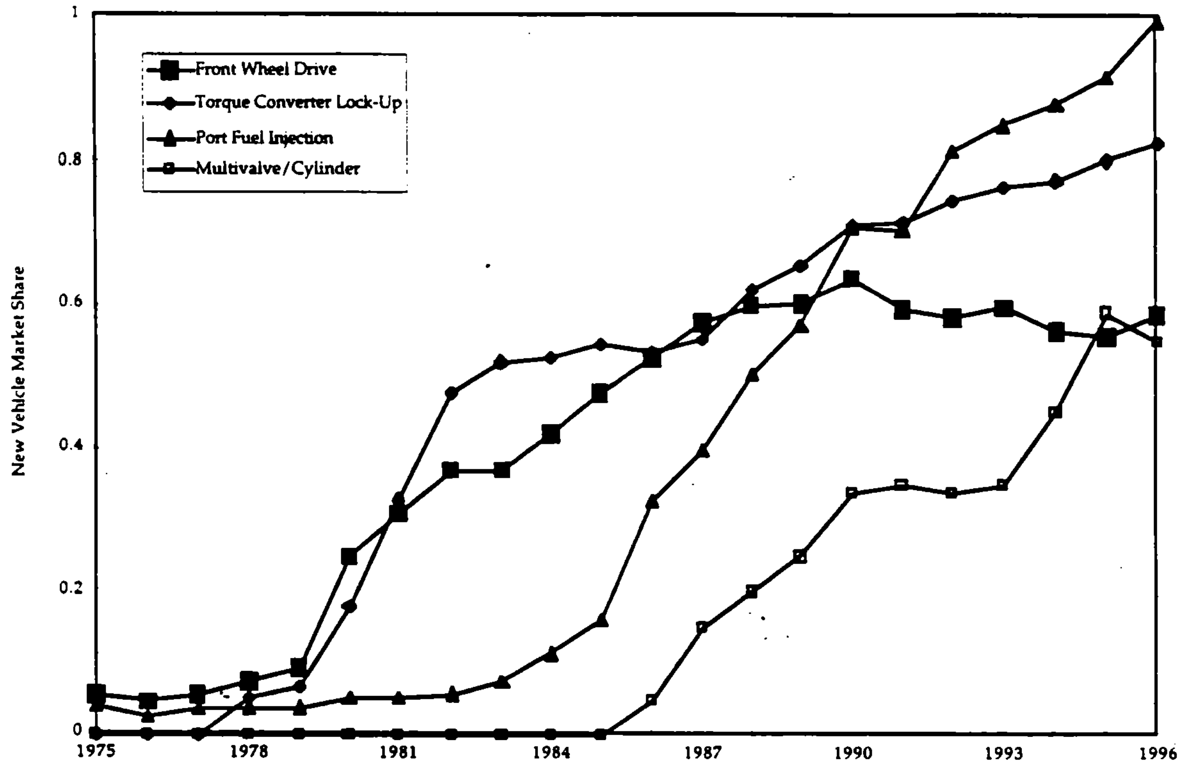
Figure 5.4 New Light-Duty Vehicle Fuel Economy and Gasoline Prices, 1967-1996



It is difficult to separate out analytically the impacts of CAFE standards and the effect of the marketplace in pushing fleet fuel economy one way or the other. However, we believe that the most likely explanation for the stagnation of fuel economy levels over the past decade is that the CAFE standards have tended to act as a floor on fuel economy, that without the standards the market level of fuel economy would have been lower than it was. We note that important fuel economy technologies, such as fuel injection, front-wheel drive, lock-up torque conversion, 4-valves per cylinder, overhead cam design, improved aerodynamics, and others, all increased their market penetration over the 1983-1997 period (Figure 5.5). Fuel economy technologies were adopted, yet average fuel economy did not increase. There are two major reasons. First, much of the potential to improve fuel economy was used instead to increase average light-duty vehicle horsepower by 55% and weight by 13% from 1983 to 1996 (Heavenrich and Hellman, 1996, Table 1). The second reason is that the impact of a technology on fuel economy depends on how that technology is implemented. To some extent, the fuel economy benefit of a technology is inherent in it. But to a degree, the benefit also depends on the details of vehicle design, specifically whether the technology is implemented with the purpose of increasing MPG or with some other purpose in mind.

If CAFE was in fact a binding constraint during the past decade and remains so today, fleet MPG will not begin to increase significantly until a market equilibrium is reached wherein actual fleet fuel economy becomes equal to the fuel economy level that would be achieved in the absence of CAFE standards. In our view, estimating "free market" fuel economy levels is basically a judgment call. We have assumed that market equilibrium will *not* be reached in the base case, so that fleet fuel economy will remain unchanged. In other words, we assume that, although fuel economy technology will continue to be adopted, it will be used to provide other benefits than fuel economy, particularly increased size and performance. Note that the AEO97 reference case also projects increased performance and size over the forecast period; the difference here is a matter of degree, not one of radically different visions of the most likely future.

Figure 5.5 Use of Fuel Economy Technology In New Light-Duty Vehicles



5.3.2 The Efficiency Scenario For Transportation

The efficiency case was created by making reasonable, incremental assumptions about how a concerted effort to accelerate the development and promote the adoption of low greenhouse gas technologies could reduce emissions by the U.S. transportation sector. In this section, the specific changes made to the business-as-usual case are described in detail.

5.3.2.1 Changes to the Modal Models

The efficiency scenario assumes that the time required for market introduction of advanced technologies can be reduced by 25% through increased emphasis on technology R&D, and that several new technologies will be developed that would otherwise not be available in significant numbers before 2010. For light-duty vehicles, these technologies include the following:

- A direct-injection stratified charge (DISC) gasoline engine,
- A turbocharged direct-injection clean diesel engine (TDI Diesel) that meets current and future emissions standards,
- Advanced drag reduction, materials substitution, and engine friction reduction (Drag VI),

- A gasoline/electric hybrid vehicle (Gasoline Hybrid), and
- A diesel/electric hybrid drive vehicle (Diesel Hybrid).

In fact, the diesel hybrid and the 2-stroke engine were not included in the efficiency scenario in order to reduce the number of new engine technologies introduced. We chose the gasoline over the diesel hybrid because its emissions of conventional pollutants can very likely be reduced to extremely low levels, making it attractive for air quality reasons. In the high-efficiency/low-carbon scenario, both the 2-stroke and the diesel hybrid are included (the 2-stroke is assumed to be applicable only in compact or smaller-sized vehicles). The result is that new powerplant technologies all but entirely replace today's conventional gasoline engine by 2015 in the high efficiency scenario. This seems a very ambitious undertaking and one that would require greater expense and a higher degree of technical success than is consistent with the efficiency scenario.

The efficiency scenario assumes a cost reduction of about one-third over estimates developed by OTA (1995) for the advanced technologies shown in Table 5.2, based on the potential for learning-based cost reductions discussed earlier. Among conventional technologies, the cost of CVTs was reduced from $250 to $150 and the cost of VVT was cut in half for passenger cars and left unchanged for light trucks. The cost reductions are intended to reflect the success of an enhanced R&D effort.

In the truck freight sector, several new technologies were brought into the forecast by reducing the fuel price threshold at which they would become attractive to buyers. These include:

- The LE-55 diesel engine with a 21% efficiency improvement for heavy trucks,
- Reduced empty weight,
- The turbo compound diesel engine, and
- Advanced drag reduction.

The low-emission, 55% thermal efficiency (LE-55) diesel engine is a research target of the U.S. Department of Energy's Office of Transportation Technologies. Compression ignition (diesel) engines are the most efficient heat engines currently available. Very large units (in stationary or marine applications) achieve thermal efficiencies (work output as a ratio to energy content of fuel) of 50%. The best turbocharged diesel engines for heavy trucks achieve 45% thermal efficiency, versus 24% for gasoline engines. The DOE's Offfice of Heavy Vehicle Technology has established a goal of 55% thermal efficiency for heavy truck engines as an intermediate target on the way to a long-term goal of 63%. These improvements are to be achieved through a combination of increased peak pressure, insulation of pistons, cylinder walls and heads to reduce heat loss, effective recovery of exhause heat, friction reduction, and improved turbocharger efficiency (U.S. DOE/OHVT, 1996).

For commercial aircraft, an efficiency improvement of 40% was projected for 2015 for new aircraft, comprised of 25% engine efficiency gains and 15% aerodynamics and materials substitution. Also, load factors were assumed to increase to 70% in accord with industry projections as a result of advanced informational and operational technologies. Finally, railroad freight efficiency per ton-mile was assumed to improve at 2% per year, actually somewhat lower than the 2.8%/yr. rate experienced over the past 20 years.

5.3.2.2 New Technologies

Table 5.2 shows the fuel economy benefits, price impacts, years of introduction, effects on vehicle weight, and effects on vehicle performance of the five new technologies that were added to the AEO97 reference case set. Detailed assumptions underlying the cost of fuel economy improvement estimates shown in Table 5.2 are provided as an appendix to this chapter. In order to meet current and future emissions standards, the DISC and TDI Diesel engines, as well as the two-stroke engine included in the business-as-usual case, will require the development of practical, lean-combustion nitrogen oxide catalysts. Catalyst technology for treatment of exhaust emissions has been advanced significantly over the past few years and, with further research, the prospects for its early commercialization appear to be very good (e.g., Buchholz, 1997; Strehlau et al., 1997). Achieving equivalent results for diesel exhaust NO_X appears to be more difficult, and commercialization of diesel catalysts is likely to occur several years after introduction of gasoline-engine catalysts (U.S. Congress, OTA, 1995). In addition, the DI Diesel will require advances in fuel and emissions control technology in order to meet likely future particulate standards.

Fuel economy benefits, incremental costs and other changes are calculated with reference to a 1995 technology gasoline vehicle. In the NEMS model, light-duty vehicles are classified into passenger cars vs. light trucks, domestic vs. imported, with six size classes for each category. In each class, the 1995 base vehicle has the average characteristics of cars in its class. For example, half of the passenger cars in 1995 had 4-valve per cylinder engines, but less than 10% of the light trucks did (Heavenrich and Hellman, 1996). Thus, the 1995 base vehicle is credited with half of the fuel economy improvement potential and half of the increased cost of 4-value technology. One hundred percent of passenger cars and 99% of light trucks had port fuel injection, and so the base year vehicles are given 100% and 99% of the fuel economy benefit and cost of fuel injection technology. Future fuel economy improvements are calculated based on the additional penetration of fuel economy technologies beyond the business-as-usual case. Thus, the ability of further use of port fuel injection to improve fuel economy is negligible, while considerable potential remains for 4-valve technology.

Table 5.2 New Light-Duty Vehicle Technologies Added to the Efficiency and High-Efficiency/Low-Carbon Scenarios*

Technology	MPG Benefit (%)* (EFF, HE/LC)	OTA Price Increase	Scenario Price	Introduction Date* (EFF, HE/LC)
DISC	18, 23	$450	$300	2000, 2000
Turbo DI Diesel	40, 40	$1100	$750	2004, 2004
Hybrid/Gasoline	33, 42	$3000	$2000	2005, 2005
Hybrid/Diesel	54, 72	$3500	$2300	2005, 2005
Drag VI	12, 12	$256	$256	2012, 2012
Gasoline Fuel Cell	–, 84	–	$800	–, 2007

* For an explanation of the assumptions underlying these estimates please see the appendix to this chapter.

5.3.2.3 Valuing Energy Savings

The NEMS model values the fuel economy savings of advanced technology by computing the expected discounted value of annual fuel savings over a payback period. We used a 7% real discount rate over five years whereas the reference case assumes an 8% real discount rate over a four-year payback period. The issue of discounting fuel savings is discussed in greater detail in Section 5.3.5.

5.3.2.4 Trends in Vehicle Performance

The NEMS model predicts consumer demand for increased performance and then adjusts new car MPG downward to reflect the effect of higher horsepower on fuel economy. The model's predictions are consistent with recent trends in light-duty vehicle performance since the early 1980s. Over this period, new vehicle fuel economy was constrained by the federal Automotive Fuel Economy Standards (CAFE) to levels higher than the market would otherwise have demanded. Gasoline prices fell precipitously, starting in 1983 and reaching pre-1974 levels by 1987 (Figure 5.4). As a result, new technology adopted since the mid-1980s, that could have increased fuel economy, was instead used to hold fuel economy constant while increasing vehicle horsepower and weight. The ratio of horsepower to weight for passenger cars increased by 50% from 1982 to 1996). The NEMS horsepower equations essentially continue this trend of ever-increasing performance.

Continued use of new technology to increase performance without increasing fuel economy is consistent with the continued low motor fuel prices projected in the AEO97 reference case. The reference case foresees gasoline prices rising from $1.15 in 1995 to $1.23 in 2010 and falling to $1.18 per gallon in 2015 (1995$). Such variations are within the noise of year-to-year fluctuations. For example, the actual average price of gasoline in 1995 was $1.20 and the average price for 1996 will likely exceed $1.30 per gallon (EIA, 1997, Table 9.4). With no increase in price and binding fuel economy standards, it is likely that performance and weight will continue to increase and fuel economy will not.

In the efficiency case, the trend toward ever greater horsepower is questionable. In the presence of higher fuel economy standards, voluntary commitments by manufacturers to meet GHG targets, "greener" consumers, externality-based fuel taxes, or some other change in policies or preferences focusing consumers' and manufacturers' attention on efficiency, it is likely that performance trends would change. Nonetheless, we retain the NEMS performance projection in the efficiency case, but relax it in the high-efficiency/low-carbon case by permitting only half of the projected increase in horsepower. This results in new vehicle fuel economy levels 1-2 MPG higher in the high-efficiency/low-carbon case than would otherwise be the case.

5.3.2.5 NEMS New Light-Duty Vehicle Fuel Economy Estimates

Transforming the technology of transportation energy use takes time. First, manufacturers must implement a new technology. New designs must be engineered, tested, and certified to meet government standards. Generally, capital equipment will also have to be replaced or retooled. The orderly replacement of long-lived production facilities (engine production lines may last 15 years, or more) is important to holding down the cost of technological change. Second, consumers must become accustomed to the new technology, and the supporting infrastructure of maintenance and repair must be developed. Finally, new technologies must compete with existing technologies and with other new technologies. In general, a single technology will not dominate all possible applications (vehicle types and consumer preferences). For all these reasons, new technologies rarely achieve 100% (or even 10%) market penetration of the new vehicle fleet in the first year of introduction. The NEMS model simulates the gradual evolution of technology market shares toward their eventual equilibrium levels by means of technology adoption curves calibrated to historical rates of adoption.

As a result, the NEMS forecast of average fuel economy for new vehicles will lag behind the full technological potential. This is illustrated in Table 5.3, which lists all of the best technology predicted to be available in 2010 and 2015 in the efficiency scenario, except that the diesel rather than the gasoline hybrid is included. The effects of regulations that are likely to reduce fuel economy are also included, but further increases in performance (horsepower/weight) predicted by the NEMS model are not, i.e., horsepower-to-weight ratios are assumed to remain constant at 1997 levels. (This applies only to Table 5.3 – all scenarios incorporate substantial increases in hp/wt ratios.) The combined effect of all technologies could improve the fuel economy of the average passenger car by 100% to 55 MPG in 2010, and by another 20% to over 60 MPG in 2015. Yet, even in the high-efficiency/low-carbon scenario, these levels are not achieved by the new car fleet in the NEMS forecasts.

Table 5.3 Maximum Technological Fuel Economy Potential Versus NEMS New Car Average Estimates

Technology	2010 Fuel Economy Improvement (%)	2015 Fuel Economy Improvement (%)
Material Substitution IV	9.9	13.2
Drag Reduction V	9.2	12.0
Engine Friction III	5.0	6.5
Tires III	5.0	7.0
ACC II	1.0	1.0
Electric Transmission II	1.5	1.5
Electric Power Steering	1.5	1.5
Air Bags	-1.0	-1.0
Emissions Tier II	-1.0	-1.0
ABS	-0.5	-0.5
Side-Impact	-0.5	-0.5
Roof Crush	-0.3	-0.3
Diesel Hybrid	54.0	60.0
Total % Improvement*	100.0	123.0

1997 MPG 27.5	2010 MPG	2015 MPG
Maximum Use of All Fuel Economy Technology		
Miles per Gallon	55.0	61.3
Percent Improvement	100	123
New Car Salesweighted Average Fuel Economy: Low CO2 Scenario		
Miles per Gallon	37.5	41.4
Percent Improvement	36	51
New Car Salesweighted Average Fuel Economy: Breakthrough Scenario		
Miles per Gallon	43.1	50.2
Percent Improvement	57	83

* Total percent improvement is computed as $[(1 * \frac{54}{100})(1 + \frac{30}{100} - 1)] * 100$. Summing rather than multiplying the smaller percentage improvements yields a more conservative estimate.

Clearly, faster rates of fuel economy improvement than predicted in either scenario are achievable, but at added cost. The constraint that fuel economy improvements be approximately cost-effective requires that the changeover of technologies and manufacturing capital occur at approximately normal rates. This causes realized new car MPG levels to lag considerably behind the full technological potential. On the one hand, this implies that considerable additional energy-efficiency improvement can be made beyond 2015. On the other, it implies that markets must be encouraged, through public policy measures, to make continuous improvements if cost-effective reductions in CO_2 emissions are to be realized.

5.3.2.6 Changes to the Heavy Truck Model

In contrast to the business-as-usual case, the efficiency scenario for heavy trucks:

- Advances introduction dates for two fuel economy technologies,
- Introduces one additional technology,
- Expands the applicability of several truck technologies,
- Reduces the "trigger price" at which the technologies are assumed to become cost-effective, and
- Accelerates the rate at which new technologies are assumed to penetrate the new truck market.

The AEO97 reference case assumes that the Turbocompound Diesel Engine and the Advanced LE-55 Heat Engine will not be available through 2015. The efficiency scenario assumes these technologies will be introduced in 2003. Advanced drag reduction, which is also excluded from the reference case for heavy trucks is assumed to have become available in 1997.

The additional technology introduced is reduction in vehicle empty weight through material substitution. Reducing vehicle empty weight by 10% should be possible, with a consequent 3% increase in fuel economy (Roberts and Greene, 1983; Greene, 1996a, Table 5.5). Reduced empty weight is assumed to be applicable to all types of heavy trucks.

The AEO97 reference case assumes that advanced drag reduction, the turbocompound diesel, and the LE-55 heat engine will be applicable only to the heaviest diesel trucks. The efficiency case extends the applicability of these technologies to medium-heavy diesel trucks, as well. However, the fuel economy benefits of advanced drag reduction are cut from 18% to 10% for medium trucks to reflect the fact that they are generally operated at lower speeds.

A key factor governing the use of fuel economy technology in the NEMS Heavy Truck Model is the "trigger price." Until market fuel prices reach the "trigger price" level specified for a technology, the technology will not be introduced. Diesel fuel prices never exceed $8.70 (1995$) per million Btu ($1.21/gal.) in the AEO97 reference case. Trigger prices for all but existing technologies, however, are $9/MMBtu, or greater in the reference case. The efficiency case assumes that all of the new technology can be made cost-effective at $8/MMBtu.[9]

Other parameters controlling the rate and extent of market penetration for technologies were also changed. One of these is the number of years until 99% of the maximum potential market penetration is achieved. For improved tires and lubricants, electronic engine controls, and electronic transmission controls, a value of 20 years is assumed in the AEO97 reference case. But for advanced drag reduction, turbocompound diesel, and the LE-55 engine, 99 years is the assumed value. For the efficiency case, all were set at 20 years. The AEO97 reference case assumed that the LE-55 engine would have a maximum market potential of 50% for heavy-duty diesels. The efficiency scenario assumes a 100% maximum for heavy diesels, but only 50% for heavy gasoline, LPG, and CNG trucks.

Likewise, the maximum market potential for other advanced technologies was increased to 100% for the heavy diesel market, but left at the reference case values for other fuel types. For medium diesel trucks the maximum penetration for new technologies was raised to 90%, but left at the reference case levels for other fuel types. These changes do not imply that any of these technologies will actually reach maximum market penetration over the forecast time period. Table 5.4 summarizes the primary fuel economy technologies for heavy trucks in the efficiency scenario for 2010.

Table 5.4 Key Heavy Truck Fuel Economy Technologies for the Efficiency Scenario in 2010

Technology	Year of Introduction	Trigger Price (1995$/MMBtu)	Maximum Market Potential (other / diesel)	Fuel Economy Improvement % (medium/heavy)
Improved Tires & Lubes	1994	$7.75	80% / 100%	10% / 6%
Electronic Engine Controls	1994	$7.75	70% / 100%	2%
Elec. Transmission Controls	1994	$7.75	75% / 100%	5% / 2%
Advanced Drag Reduction	2000	$7.75	25% / 100%	7% / 18%
Turbocompound Diesel	2000	$7.75	25% / 100%	15% / 17%
LE-55 Heat Engine	2003	$7.75	50% / 100%	19% / 21%
Reduced Empty Weight	1997	$7.75	90% / 100%	3%

5.3.2.7 Changes to the Rail Model

The AEO97 reference case scenario assumes an annual rate of reduction in rail freight energy use per ton-mile of 1%. Since 1972, the average annual rate of reduction in energy use per ton-mile has been 2.8% per year. The vast majority of this improvement has been due to operational efficiency improvements reflected in increased load factors per car (Greene and Fan, 1995, p. 15). Higher load factors are partly due to the restructuring of the rail industry following deregulation in 1980, and partly due to the use of advanced technology for managing operations. Technologies such as lighter weight and higher capacity cars, lower resistance axle bearings, rail-wheel lubrication and improved efficiency locomotives also played an important role (Cataldi, 1995). These technologies are, as yet, still only partially implemented. Based on Cataldi (1995), advanced technologies that can play a role in substantially reducing rail energy use in the future include the following:

- **Flywheels:** Trains presently give up large amounts of kinetic energy on downgrades that could be transferred to flywheels and later used to power the train. The volume and mass necessary to store huge quantities of power can be readily accommodated on trains.

- **Oxygen-enrichment to increase engine thermal efficiency:** Membranes that exclude part of the free nitrogen in the air, thereby enriching the oxygen concentration, can be incorporated into locomotives' air filtration systems. This technology should benefit new, higher power density engine designs, while helping to hold down their nitrogen oxide emissions.

- **Alternative fuels:** Railroads and locomotive manufacturers have been studying and testing the use of natural gas fired locomotives. Once again, the ability of trains to accommodate the volume and mass of storage systems for liquefied natural gas gives them a distinct advantage over smaller vehicles in the application of this technology. Although natural gas locomotives are not expected to provide energy-efficiency gains over diesels, natural gas will produce fewer CO_2 and NO_X emissions and reduce U.S. dependence on oil.

- **Fuel cells:** Beyond 2010, fuel cells for locomotives hold promise. Locomotives already use electric drive systems. And carrying fuel, even compressed hydrogen in large volumes, is less of a problem for trains than for highway vehicles.

Because existing energy-efficiency technologies have yet to achieve full utilization, because other promising options exist, and because further operational efficiency gains are likely with the advance of information technology and some additional railroad consolidation, rail energy-efficiency improvements could continue at a substantial rate. A concerted effort to develop and implement cost-effective technologies is represented here by a 2% annual improvement in ton-mile efficiency in the efficiency case compared with the 1% rate assumed in the AEO97 reference case.

5.3.2.8 Changes to the Air Model

No new technologies were introduced in the NEMS Air Travel Model, but several important changes were made to promote and accelerate the introduction of fuel efficient technology in accordance with goals set by the Committee on Aeronautical Technologies, Aeronautics and Space Engineering Board of the NRC. Broadly, these goals call for a reduction in fuel burn per seat of about 40% by the 2010 to 2015 time period, to be achieved through a combination of improved propulsion system performance (25%) and aerodynamic and weight improvements (15%) (NRC, 1992, p. 49).

Once again, in the AEO97 reference case, new technologies do not enter the commercial aircraft market because trigger prices are set well in excess of $1.00 per gallon and jet fuel prices never exceed $0.80/gal. over the forecast period. Trigger prices for ultra-high bypass turbo-fans, already in use on the new Boeing 777s, were lowered to $0.58/gal., just slightly above current jet fuel prices. Advanced aerodynamics, weight reduction through advanced materials use, and improved engine thermodynamics, were all given the same, lower trigger price. The prices of turboprop engines and laminar flow control were left at levels high enough to prohibit their introduction on new aircraft through 2015.

Ultra-high bypass turbofans were introduced in 1995. The other three technologies were assumed to be introduced in 2000. Consistent with estimates presented in NRC (1992), Greene (1992, Table 4), and Greene (1996b), the efficiency improvement potentials for all four new technologies were set at 15%.

Finally, the AEO97 reference case predicts no changes in aircraft load factors. Aircraft industry analyses foresee commercial load factors increasing to 70% by 2015 (Boeing, 1995, p. 25; McDonnell Douglas, 1996, p. 18). The industry view is adopted in the efficiency scenario, on the grounds that it will very likely be advances in information technology that permit the increase in load factors. On the other hand, although the industry predicts an increase in aircraft size (seats/aircraft) of about 15% by 2015 while the AEO97 reference case does not, no such increase is included in the efficiency scenario on the grounds that more seats per aircraft will be less a reflection of technological change than of airframe choice.

5.3.2.9 Introduction of Cellulosic Ethanol

Alternative fuels derived from fossil fuels have limited potential to reduce greenhouse gas emissions. The full fuel cycle greenhouse gas emissions of fossil fuels have been compared in detail by Delucchi (1991, Table 9a), Wang (1996), U.S. DOE (Leiby et al., 1996, Tables D-4 and D-5), and others; see Wang (1996) for a review. Several fuel alternatives have lower CO_2 emissions than conventional or reformulated gasoline (RFG), most notably liquefied petroleum gases (LPG), methane and battery-powered electric vehicles in certain regions, whether compressed (CNG) or liquefied (LNG). Estimates of greenhouse gas emissions are strongly dependent on context and assumptions. Absolute levels and sometimes the relative rankings of fuels vary across studies. Several general patterns seem to hold up, however. For example, fossil-fuel based alternatives to gasoline or diesel fuel, including battery-electric vehicles where substantial amounts of coal are used for electricity generation, offer about a 20% net reduction in greenhouse gas emissions per mile (Figure 5.3).

In the context of this analysis, a 20% reduction in greenhouse gas emissions will not create a strong incentive to adopt an alternative fuel. For light-duty vehicles, if society's willingness to pay for greenhouse gas emissions reductions were on the order of \$25-\$50 per tonne of carbon, this could justify up to a \$0.06 to \$0.12 per gallon subsidy[10] for a fuel that produced no greenhouse gas emissions. A 20% reduction would therefore be worth \$0.01 to \$0.02 per gallon, hardly enough to get motorists' attention. Also, the principal near-term alternative fuels entail some increase in vehicle cost or loss of amenity (Leiby et al., 1996). Thus, unless much higher incentives are introduced, it is unlikely that enough substitution of alternative fossil fuels for conventional gasoline will occur to produce significant greenhouse gas reductions in transportation (Leiby et al., 1996).

Alternative fuels produced from renewable biomass feed stocks can yield significant reductions in greenhouse gas emissions. The most recent estimates indicate that ethanol derived from cellulosic feed stocks (as opposed to grain) produces less than 1% as much greenhouse gas emissions on a fuel cycle basis as conventional gasoline or diesel fuels (Singh, 1997).[11] Table 5.5 shows the greenhouse gas emission coefficients used to estimate the effects of cellulosic ethanol use and increased demand for diesel fuel on transportation sector greenhouse gas emissions. Ethanol from cellulose generates negligible amounts of greenhouse gases in comparison to fossil fuels or ethanol from grain. Whether ethanol is derived from grain or woody biomass, the carbon in the fuel itself does not count because equivalent carbon will be recaptured from the atmosphere by the next rotation of crops. The differences lie in feed stock cultivation, fertilizer manufacture, and fuel production. Corn requires more cultivation and more fertilizer than woody crops, and fertilizer production, in particular, generates significant greenhouse gas emissions. Whereas distillation of alcohol after the fermentation of grain is energy intensive, by-products from the wood-to-alcohol process will produce excess power, on net, resulting in a greenhouse gas credit for replacing fossil fuels with biomass in the generation of electricity. Indeed, given current practice, ethanol from corn may produce more greenhouse gas emissions than gasoline, on a per Btu basis. Thus, ethanol from cellulosic feed stocks will not only reduce greenhouse gas emissions by replacing gasoline, but might achieve even greater benefits by replacing ethanol from corn. However, the net greenhouse gas balance of ethanol production from corn is strongly dependent on future corn yields, the market for distillation byproducts, and the efficiency of and fuel used in distillation (currently, coal is often the preferred fuel because of corn-based ethanol's disadvantage in greenhouse gas emissions, but future widespread use of corn stillage as fuel would swing ethanol's greenhouse gas emissions strongly towards a positive balance).

A new process for producing ethanol from cellulosic biomass that appears to have the potential to dramatically reduce costs is under development by the U.S. DOE's National Renewable Energy Laboratory (Chem Systems, Inc., 1993). After initial preparation of the biomass, pretreatment with sulfuric acid and then steam is used to expose the cellulose and convert xylan to xylose. Two percent of the resulting mixture is separated for conversion to cellulase, an enzyme that hydrolyzes cellulose. The cellulase is then combined with the rest of the mixture fermented in a key step known as simultaneous saccharification and fermentation (SSF) because the hydrolyzation of cellulose and the fermentation of xylose occur simultaneously. The inclusion of xylose fermentation in this step increases the output of ethanol by about 25% over previous processes. Effluent from the SSF process goes to an ethanol purification and solids separation phase, which produces ethanol and solids. After removal of water, the solids are burned as fuel to cogenerate steam and electricity required for the plant, with surplus electricity that can be sold as a byproduct.

Table 5.5 Greenhouse Gas Emissions Factors for Transportation Fuels

Fuel	g/Btu	Btu/gallon	g/gallon
Conventional Gasoline			
Summer	0.10554	114,500	12,084
Winter	0.10304	112,700	11,613
Average	0.10421	113,537	11,832
Diesel	0.09617	128,700	12,377
Ethanol from corn	0.13390	76,100	10,190
Ethanol from cellulose	0.00076	76,100	58

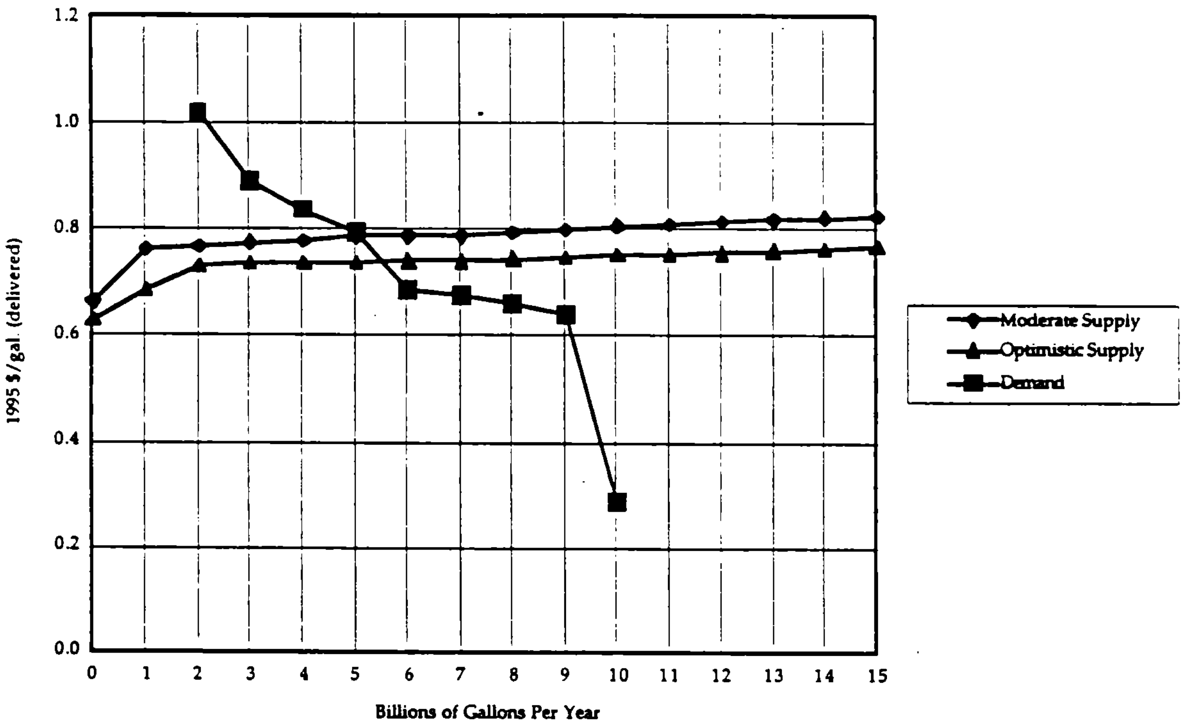
Source: Singh (1997)

Initial estimates of the cost of ethanol produced by the NREL process ranged from $0.78 to $1.27 (1990$) per gallon, plant gate price (Chem Systems, 1993, Tables II-9 to II-13). However, recent cost projections (Bowman et al., 1997) based on a comprehensive assessment of feed stock supply in the United States (Walsh et al., 1997) and anticipated improvements in the ethanol conversion process predict that much lower production costs can be achieved by 2010 or 2015. Ethanol can be produced from a variety of cellulosic feed stocks: short rotation woody crops, switch grass, softwood and hardwood wastes, agricultural residues, and even municipal solid wastes. Selecting the lowest cost feedstock at each level of output, aggregate ethanol supply curves were constructed for 2000, 2005, 2010, and 2015 under "moderate" and "optimistic" assumptions. The optimistic curves assume that the yield improvements of the moderate case are accelerated by five years, with the net result that the real cost of feed stocks does not rise over time. The moderate scenario curves are used in the efficiency scenario. The optimistic case, being similar in intent to our high-efficiency/low-carbon scenario, is used in that scenario.

In the moderate scenario, ethanol production costs drop dramatically after 2005, the year in which advanced ethanol conversion technology is assumed to be introduced. In 2000, the first billion gallons cost $1.10 (1995$) per gallon at the plant gate, which rises to almost $1.25 per gallon at a 10 billion gallon output level. These prices exclude motor fuel taxes and transportation costs. By comparison, the average refinery price of all grades of gasoline in 1995 was $0.63 per gallon (EIA, 1996a, Tables 5.20 and 5.21). Because ethanol has only about two-thirds of the energy content of gasoline, the comparable price of ethanol per gasoline energy equivalent gallon would be $1.63 for the first billion gallons and $1.85 at the 10 billion gallon level of output. By 2010, the cost of ethanol drops to about $0.75 per gallon ($1.11 per gasoline equivalent gallon) at the 1 billion gallon output level, $0.79/gallon ($1.17 equivalent) at 10 billion gallons of production. Even in the optimistic case, the first billion gallons cost $0.67/gallon ($.99 equivalent), increasing to $0.73/gallon ($1.08 equivalent) at the 10 billion gallon output level. Despite dramatic reductions in the cost of producing ethanol from biomass, because of the lower energy content of ethanol, ethanol still cannot compete with gasoline as a pure fuel.

We conclude that the market for cellulosic ethanol in 2010 will be largely as a blending component for gasoline. Demand curves for ethanol for blending with gasoline have been estimated by Hadder (1997) for the year 2010. These show the value to refiners of being able to produce a gasoline refined to be blended with alcohol downstream. Ethanol increases the gasoline's octane rating and adds oxygenates that are required in certain areas under the Clean Air Act. The demand for ethanol as a blending component turns out to be sensitive to the market share of RFG. The more RFG that is required, the lower the demand for ethanol. We assume that RFG's market share remains at its current level of about 30%. Estimated ethanol demand increases as its price declines, from 2 billion gallons per year at an ethanol price of just over $1 per gallon to 5 billion gallons at $0.80/gallon and 9 billion at $0.65/gallon. From this point, increases in demand associated with further price decreases drop off sharply as the limits of economical blending are reached. The moderate 2010 supply curve for cellulosic ethanol intersects the demand curve at about 5 billion gallons per year (Figure 5.6).

Figure 5.6 Biomass Ethanol Supply and Demand for Ethanol in Gasoline Blending



These calculations include no tax subsidy for cellulosic ethanol from biomass. If the projected supply curves are correct, cellulosic ethanol would require no subsidy to be economically attractive as a blending component for gasoline. The current tax subsidy for ethanol – now produced from grain – is due to expire, and the future of the industry is uncertain. Assuming discontinuation of the subsidy, cellulosic ethanol would displace corn-based ethanol from the gasohol, yielding significant greenhouse gas emissions reductions.

5.3.2.10 Adjustment of NEMS Gasoline Forecast

The 5.5 billion gallons of cellulosic ethanol demanded in the efficiency case reduce greenhouse gas emissions by 13 million tonnes of carbon equivalent in 2010 compared to the business-as-usual case. Cellulosic ethanol is assumed to replace first corn-based ethanol, and then conventional gasoline. The Federal Highway Administration (FHWA) estimates that 1.214 billion gallons of ethanol were used in gasohol in 1995 (U.S. DOT/FHWA, 1996, Table MF-33E). If gasohol made from corn-based ethanol were to maintain a constant share of the gasoline market, then corn-based ethanol use would grow to 1,263 million gallons in 2010, then shrink to 1,119 million gallons in 2015. Table 5.6 shows the projected demand for cellulosic ethanol, the corn-based ethanol assumed to be replaced and the impact on fuel cycle greenhouse gas emissions. Because the upstream effects cannot be assumed to be accounted for in the other sectoral models, they are included here. Note that the reduction is shown in tonnes of carbon, while the emissions before and after are in tonnes of CO_2.

Table 5.6 Impact of Cellulosic Ethanol on Greenhouse Gas Emissions from Light-Duty Vehicles in 2010

	Efficiency	Optimistic
Cellulosic Ethanol (million gallons)	5,514	7,480
Corn Ethanol Displaced (million gallons)	1,263	1,119
Gasoline Equivalent Energy Displaced (million gallons)	3,696	5,014
GHG Emissions Before (million tonnes CO_2 per year)	46.6	62.2
GHG Emissions After (million tonnes CO_2 per year)	0.3	0.4
GHG Emissions Reduction (million tonnes C per year)	12.6	16.8

5.3.2.11 Adjustments for Increased Light-Duty Vehicle Diesel Use

Because the TDI Diesel engine and the Diesel-hybrid technologies were introduced in the NEMS Transportation Sector Model as fuel economy technologies, the fuel-type accounting algorithms of NEMS were bypassed. We introduced the advanced diesel in this way because we believe that its characteristics will be more similar to gasoline engines than the diesels available in the past. The TDI will fully meet all gasoline vehicle standards and will be quite similar in terms of performance, noise, and odor.[12] Thus, an adjustment must be made *ex post*, to transfer an appropriate amount of energy from the gasoline to the distillate category. The adjustment affects the energy use projections in three (relatively minor) ways. First, the TDI Diesel's impact is specified in terms of a change in miles per gallon. Since diesel fuel contains more Btu per gallon than gasoline and since the NEMS model assumes that gasoline is being consumed, the energy use transferred from gasoline to diesel must be increased by the ratio of diesel to gasoline Btus per gallon. Second, distillate fuel produces slightly less carbon emissions per Btu than gasoline. Therefore the estimated carbon emissions must be adjusted both for the slight increase in energy use and the slightly lower emissions per Btu for that greater energy use (the net result is a very small increase in carbon emissions). Third, and finally, the reduction in gasoline use reduces the potential pool for ethanol blending in gasoline. As a result, the demand for ethanol must be adjusted downward to reflect the lower level of gasoline use. The net result of all of these changes on energy use and carbon emissions is less than 1%.

5.3.3 The High-Efficiency/Low-Carbon Scenario for Transportation

The high-efficiency/low-carbon scenario postulates the introduction before 2010 of several new technologies and combines them with other changes to reflect greater success in developing and implementing low greenhouse gas technologies and greater public concern over greenhouse gas emissions. Note that successfully achieving these outcomes requires some technological breakthroughs, implying that the outcomes are significantly less certain than those in the efficiency case. As we pointed out in the introduction to this chapter, the high-efficiency/low-carbon scenario is best characterized as an "optimistic" version of the efficiency scenario's "most likely" assumptions. Both must be considered responses to intensified R&D efforst and new policy measures to push the market toward low-carbon technologies. A $50/ton carbon tradable permit price could be one of the necessary policies, but it does not define the difference between our efficieny and high-efficiency scenarios.

5.3.3.1 Light-Duty Vehicles

Changes for light-duty vehicles include introducing a fuel-cell hybrid in the year 2007 and reintroducing the diesel hybrid and the 2-stroke engine for smaller vehicles. In the projections shown here, we assume that the fuel cell hybrid vehicle uses gasoline which is reformed to provide hydrogen for the fuel cell's operation (e.g., Jost, 1997). The vehicle could just as easily have been designed to operate on alcohol fuels. The gasoline fuel cell hybrid achieves an 84% efficiency gain over a conventional gasoline vehicle, assuming major progress not only in fuel cell and gasoline processor technology, but also in electric motors and other electric drivetrain components. Because a major breakthrough would be required to make this vehicle marketable, we do not attempt to estimate its cost. Instead, we assume that it will be cost-effective on a life-cycle cost basis – that is, that its incremental cost will be equal to its lifetime fuel savings. This implies a price increment of $800. Note that this value is not meant to be interpreted as a forecast of likely future fuel cell costs; instead it allows us to evaluate the consequences of such an optimistic outcome.

Some of the technologies necessary to produce an 84% efficiency gain for the fuel cell hybrid would also make the internal combustion engine hybrids, both gasoline and diesel, somewhat more efficient (e.g., ultra high-efficiency electric motors, improved energy storage devices with high specific power and high in/out efficiency). Fuel economy gains for the gasoline and diesel hybrids are boosted to 42% and 72%, respectively. A more optimistic assumption is made for the DISC engine, as well. Its fuel economy benefit is increased to 23% from 18%.

If Intelligent Transportation Systems technologies are highly successful, they should be able to improve traffic flow, resulting in higher on-road fuel economy. To reflect this, the on-road fuel economy factor, which otherwise deteriorates by 3% from 1997 to 2015, is held constant. The high-efficiency/low-carbon case further assumes that the current emphasis on horsepower (HP) will abate substantially, although increased HP will still be valued. This case is consistent with a change in attitudes favoring "greener" automobiles or policies to encourage higher MPG. To reflect greater public concern over greenhouse gas emissions, the demand for increased horsepower is reduced by decreasing its sensitivity to income, from an elasticity of 0.9 to 0.5.

As noted earlier, there are other potential technology breakthroughs capable of significantly reducing greenhouse emissions (e.g. breakthroughs in batteries for electric vehicles, or in gas storage for natural gas vehicles (see box)). These were left out of the high-efficiency/low-carbon scenario not because they are necessarily less plausible than fuel cells, but because the inclusion of large numbers of technology breakthroughs in a single scenario would be implausible.

Other Potential Breakthrough Technologies

Aside from the new technologies postulated in the high-efficiency/low-carbon scenario, other potential technologies could yield substantial reductions in greenhouse gas emissions with technology breakthroughs or, in some cases, with a substantial market push. In the light-duty vehicle market, for example, battery electric vehicles have potential to reduce greenhouse gases if they can greatly increase their market share and improve their energy efficiency. For example, several recent studies have concluded that, under plausible assumptions about EV efficiency and the mix of fuels and technology used to generate recharge electricity, use of EVs will yield net reductions of greenhouse gases. Delucchi (1997) estimates a national average reduction of 26% in 2015, with power generation heavily weighted to coal; whereas Wang (1997) estimates a 19% reduction in 2005. Areas with predominately natural gas-generated electricity could have much larger savings. Note, however, that these results are dominated by assumptions about EV and baseline gasoline vehicle efficiency, type of fuel and technology used for power generation, inclusion or exclusion of non-CO_2 greenhouse gases, and the types of trips replaced by EV use; it is relatively easy to construct plausible scenarios with much higher or lower reductions in greenhouse gases, or even increases (with coal-fired electric power and extremely efficient competing gasoline vehicles).

Crucial technological roadblocks for EV market penetration are:

- Battery improvements – especially higher specific energy and power, lower cost, improved longevity, higher in/out efficiency,
- Power electronics – especially lower cost, and
- Electric motors – especially higher efficiency over a range of driving cycles and higher specific power.

There are claims that transportation use of alternative fuels other than electricity (particularly compressed natural gas) will yield strong greenhouse benefits. In natural gas's case, recent analyses have shown contrasting greenhouse effects. For example, Delucchi (1997) estimates a 20% reduction in greenhouse gases compared to gasoline use in 2015, whereas Wang (1997) estimates a 5% *increase* in 2005. The primary difference in the two analyses is that Wang computes a 10% energy-efficiency penalty associated with switching to CNG, based on recent test data; Delucchi estimates an 11% improvement in energy efficiency based on potential efficiency gains from higher compression CNG engines. Delucchi's optimism may well be the more appropriate approach for the longer term, but at best CNG offers only a modest greenhouse emissions improvement.

Although we selected fuel cell vehicles fueled by gasoline (with onboard fuel processors) as the "breakthrough" technology in the high-efficiency/low-carbon scenario, some analysts believe that the direct use of hydrogen as a fuel is sufficiently more attractive to outweigh the disadvantages of hydrogen's low energy density (complicating onboard storage) and lack of a supply infrastructure (Ogden, 1977). The advantages of direct hydrogen include avoidance of the added weight and cost of the fuel processor and larger fuel cell required (fuel cell performance is reduced because the processor does not produce pure hydrogen), and reduced vehicle efficiency because of the energy losses in the processor and added vehicle weight (assuming the higher fuel storage weight for hydrogen is less than the weight savings from removing the processor and reducing fuel cell size). Although lack of infrastructure still represents a barrier, there have been advances in small scale-steam reforming of natural gas that could greatly ease the introduction of a viable hydrogen supply infrastructure (Ogden, 1977).

5.3.3.2 Changes to the Medium and Heavy Truck Model

Medium heavy trucks are typically operated locally in pick-up and delivery mode. For such vehicles, hybrid technology, with regenerative braking and energy storage capabilities, should offer significant advantages. It is assumed that a diesel hybrid becomes available to heavy trucks starting in the year 2005. This technology is assumed to offer the same 72% fuel economy benefit as the light-duty vehicle version.

Greater success in materials, aerodynamics, tires, and engines, should make these technologies more economically attractive to truckers. Since the NEMS Heavy Truck Model does not explicitly include an economic trade-off between fuel savings and technology penetration, this effect was simulated by shortening the time to 99% penetration for each technology by 30%. For most technologies, this implies a 15 year period from time of introduction to nearly full market penetration.

5.3.3.3 Changes to Other Modes

Several changes were made to the commercial air model inputs. Starting in 2005, propfans were assumed to be available for smaller commercial aircraft. Propfans offer a 20-30% efficiency improvement over high bypass turbofan engines, and 10-15% over even ultra-high bypass engines. Development of propfans has been hindered by concerns about initial cost, maintenance, and vibration. Propfans are made available to only one-third of new aircraft in the high-efficiency/low-carbon scenario. Additionally, partial success in hybrid laminar flow (HLF) technology to reduce drag is assumed by 2010. Although HLF has the potential to reduce fuel use by 15% or more, only a 9% efficiency gain is assumed due to the continuing difficulties in developing a practical system. In the efficiency case, ultra-high bypass engines are assumed to give a 10% efficiency gain, thermodynamic improvements provide a 15% gain, and advanced aerodynamics yield an 18% improvement. In this case, those are increased to 17%, 18% and 27%, respectively, certainly optimistic but not implausible estimates (for example, see Greene, 1992, Table 4).

The annual efficiency improvement rate for railroads is increased to 2.5%, still slightly lower than the 2.8% rate achieved over the past two decades. Waterborne freight's efficiency improvement rate is bumped up to 1% per year from 0.05% to reflect a 10% total efficiency gain achievable through improved hull designs and coatings. In fact, these modes have substantial potential to use alternative power plants and fuels, as reflected in the 2020 technology discussion below.

5.3.4 Comparison of Forecasts

The efficiency and high-efficiency/low-carbon scenarios indicate that advanced energy technologies could reduce emissions of greenhouse gases from transportation by 12-17% by 2010 and by 18-25% by 2015 (Table 5.7). Although these are large changes, they may appear modest compared to the changes in new vehicles, the "leading edge" of changes in the entire transportation fleet. Changing the technology of transportation requires turning over a vast stock of vehicles, and this requires decades. As a result, the impact of advanced technologies introduced between now and 2010 will only just begin to be felt in 2010 and will still not have achieved its full effect by 2015. This phenomenon can be most easily seen by comparing the fuel economy of new cars and light trucks to that of the entire fleet of light-duty vehicles. In the efficiency case in 2015, for example, new cars average 41.4 MPG and light trucks 31.9 MPG (EPA-rated fuel economy), but the fleet as a whole lags behind at 28.2 MPG (24.0 MPG onroad). Given enough time to turn over the stock of vehicles, the eventual light-duty fleet MPG will climb about one-third higher to nearly 38 MPG (32 MPG onroad). The time lag required for new technology to penetrate the light-duty vehicle fleet is a common feature of all modes. Thus, the energy savings and greenhouse gas reductions shown in Tables 5.7 and 5.8 for 2010 and 2015 reflect less than half of the ultimate savings that the technology introduced over this period will eventually achieve.

Passenger car and light truck fuel economy improvements are, in general, attributable to the combined effect of many fuel economy technologies rather than a single, dominant technology. A number of improvements to conventional engines combine to increase average new vehicle MPG in 2010 by almost 20% for passenger cars and by about 10% for light trucks. These include engine friction reduction, greater use of multi-valve engines, and variable valve timing and lift control. Substitution of lighter weight materials, aerodynamic drag reductions, various transmission improvements, and the combined effects of advanced lubricants, tires, and accessories, each contribute 2-5% gains. Of all the technologies added to the efficiency and high-efficiency scenarios, the lean-burn gasoline engines (DISC and 2-stroke) deliver the greatest fuel economy benefits, about 15% for passenger cars and 12% for light trucks. These numbers represent sales weighted average effects, taking into consideration the fact that even in 2010 new vehicles are not equipped with these technologies. Diesel and hybrid technologies each boost average new car and light truck fuel economy by about 5% in 2010, their smaller impact being due to their smaller market shares.

The sales weighted average impacts of nine classes of fuel economy technologies in the high-efficiency/low-carbon case are illustrated in Figures 5.7 and 5.8. The measured percent fuel economy gain applies to the impact of the technology on the average fuel economy of all new passenger cars or light trucks and, thus, takes into account the estimated market penetration for each category of technologies. In 2010, passenger cars get a considerably greater benefit from engine efficiency improvements than light trucks, but the gap narrows considerably by 2015. Although the DISC and 2-stroke technologies are the most significant new technologies in 2010, the gasoline fuel cell comes on strong by 2015. The impact of the fuel cell in 2010 is obviously limited by the assumption that it would be first introduced in 2007. The impacts shown in Figures 5.7 and 5.8 depend entirely on the cost, fuel economy benefit, and introduction date assumptions shown in Table 5.2, and the way the NEMS model translates those assumptions into market success. Thus, the graphs do not represent a prediction of what specific technologies will achieve, but rather an illustration of what could happen given the outstanding successes in fuel economy technology R&D, as reflected in our high-efficiency/low-carbon scenario assumptions.

The 23% gain for light-duty vehicles in 2015 is just slightly higher than the 21% and 22% improvements by freight trucks and rail in the efficiency scenario. Aircraft efficiency gains seem to lag behind at a mere 9% in 2015, but this is due to the fact that air passenger efficiencies increase the most (17%) in the business-as-usual case. In 2010, rail and air have made the greatest efficiency gains over 1997. This is consistent with the record of the past quarter century, during which time these two modes have led all others in energy-efficiency improvement.

Table 5.7 Transportation Sector Projections to 2010 and 2015 Efficiency Scenario (cont. next page)

	1997	2010		Change v. BAU	
	BAU	BAU	Efficiency	Change	% Change
Energy Use (quads)	25.5	32.3	29.3	-3.1	-9%
Carbon Emissions (MMtC/Yr.)[1]	487	616	543	-73	-12%
Passenger Cars**	171	184	160	-24	-13%
Light Trucks	113	166	143	-23	-14%
Other Modes	203	266	240	-26	10%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.0	15.2	-2.8	-15%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.5	0.5	***
Distillate	4.6	5.8	5.7	-0.1	-2%
Jet Fuel	3.6	4.7	4.2	-0.5	-11%
Residual	1.2	1.6	1.6	0.0	0%
Other	1.1	2.2	2.1	-0.1	-4%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	18.2	16.3	-2.0	-11%
Passenger Cars**	8.8	9.6	8.6	-1.0	-11%
Light Trucks	5.8	8.6	7.7	-2.0	-11%
Freight Trucks	5.6	6.8	6.3	-0.5	-8%
Air	3.6	4.7	4.2	-0.5	-11%
Rail	0.5	0.5	0.4	-0.1	-16%
Marine	1.7	2.3	2.3	0	0%
Pipeline	0.8	0.9	0.9	0	0%
Other	0.2	0.3	0.3	0	0%
Energy-efficiency Indicators					
New Car MPG+	27.5	27.8	37.5	9.7	35%
New Light Truck MPG	20.5	20.6	27.1	6.5	32%
Light-Duty Fleet MPG	19.6	19.4	21.5	2.1	11%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	58.2	61.6	3.4	6%
Freight Truck Fleet MPG	5.6	6.0	6.8	0.8	13%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.0	3.6	0.6	20%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2762	2774	12	0%
Freight Truck VMT	173	237	238	1	0%
Commercial Air Seat-Miles	1116	1729	1608	-121	-7%
Rail Ton-Miles	1208	1459	1464	5	0%
Marine Ton-Miles	892	1047	1050	3	0%

Note: Because some light truck energy use is included in the freight truck sector, the totals by mode will not add to the totals by fuel type.

* After all scenarios had been completed, a minor error was discovered in the NEMS passenger car fuel economy technology input data. This error allowed four wheel drive improvements to be applied to certain categories of cars to which they are, in fact, not applicable. The overall effect on new car fuel economy is less than 0.3 MPG in 2010 and less than 0.5 MPG in 2015.

** Motorcycles, which are always less than 1%, are included with passenger cars.

Table 5.7 Transportation Sector Projections to 2010 and 2015 Efficiency Scenario (Continued)

	1997	2015		Change v. BAU	
	BAU	BAU	Efficiency	Change	% Change
Energy Use (quads)	25.5	34.0	28.7	-5.2	-15%
Carbon Emissions (MMtC/Yr.)	487	646	532	-114	-18%
Passenger Cars	171	192	154	-38	-20%
Light Trucks	113	174	133	-41	-24%
Other Modes	203	280	245	-34	12%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.7	13.5	-5.3	-28%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.4	0.4	***
Distillate	4.6	6.0	6.5	0.5	8%
Jet Fuel	3.6	5.0	4.2	-0.7	-15%
Residual	1.2	1.8	1.8	0.0	0%
Other	1.1	2.5	2.4	-0.2	-6%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	19.1	15.5	-3.6	-19%
Passenger Cars	8.8	10.0	8.3	-1.7	-17%
Light Trucks	5.8	9.1	7.2	-1.9	-20%
Freight Trucks	5.6	7.1	6.3	-0.8	-12%
Air	3.6	5.0	4.3	-0.7	-15%
Rail	0.5	0.5	0.4	-0.1	-20%
Marine	1.7	2.5	2.5	0.0	0%
Pipeline	0.8	0.9	0.9	0.0	0%
Other	0.2	0.3	0.3	0.0	0%
Energy-efficiency Indicators					
New Car MPG	27.5	27.9	41.4	13.5	48%
New Light Truck MPG	20.5	20.6	31.9	11.3	55%
Light-Duty Fleet MPG	19.6	19.5	24.0	4.5	23%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	60.6	66.1	5.5	9%
Freight Truck Fleet MPG	5.6	6.1	7.4	1.3	21%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.2	3.9	0.7	22%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2914	2937	23	1%
Freight Truck VMT	173	250	251	1	0%
Commercial Air Seat-Miles	1116	1923	1759	-164	-9%
Rail Ton-Miles	1208	1535	1540	5	0%
Marine Ton-Miles	892	1099	1102	3	0%

Table 5.8 Transportation Sector Projections to 2010 and 2015 High-Efficiency/Low-Carbon Scenario (cont. next page)

	1997	2010		Changes v. BAU	
	BAU	BAU	HE/LC	Change	% Change
Energy Use (quads)	25.5	32.3	27.9	-4.5	-14%
Carbon Emissions (MMtC/Yr.)	487	616	512	-104	-17%
Passenger Cars**	171	184	147	-37	-20%
Light Trucks	113	166	132	-34	-21%
Other Modes	203	266	233	-33	-12%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.0	13.9	-4.2	-23%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.7	0.7	***
Distillate	4.6	5.8	5.7	-0.1	-2%
Jet Fuel	3.6	4.7	4.0	-0.7	-14%
Residual	1.2	1.6	1.6	0.0	0%
Other	1.1	2.2	2.1	-0.2	-8%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	18.2	15.2	-3.0	-17%
Passenger Cars**	8.8	9.6	8.0	-1.6	-17%
Light Trucks	5.8	8.6	7.2	-1.4	-17%
Freight Trucks	5.6	6.8	6.2	-0.6	-9%
Air	3.6	4.7	4.1	-0.7	-14%
Rail	0.5	0.5	0.4	-0.1	-25%
Marine	1.7	2.3	2.3	-0.0	-1%
Pipeline	0.8	0.9	0.9	0.0	0%
Other	0.2	0.3	0.3	0.0	0%
Energy-efficiency Indicators					
New Car MPG+	27.5	27.8	43.1	15.3	55%
New Light Truck MPG	20.5	20.6	30.8	10.2	50%
Light-Duty Fleet MPG	19.6	19.4	23.2	3.8	20%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	58.2	64.6	6.4	11%
Freight Truck Fleet MPG	5.6	6.0	7.0	1.0	17%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.0	4.0	1.0	34%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2762	2806	44	2%
Freight Truck VMT	173	237	238	1	0%
Commercial Air Seat-Miles	1116	1729	1619	-110	-6%
Rail Ton-Miles	1208	1459	1467	8	1%
Marine Ton-Miles	892	1047	1051	4	0%

Note: Because some light truck energy use is included in the freight sector, the totals by mode will not add to the totals by fuel type.

+ After all scenarios had been completed, a minor error was discovered in the NEMS passenger car fuel economy technology input data. This error allowed four wheel drive improvements to be applied to certain categories of cars to which they are, in fact, not applicable. The overall effect on new car fuel economy is less than 0.3 MPG in 2010 and less than 0.5 MPG in 2015.

** Motorcycles, which are always less than 1%, are included with passenger cars.

Table 5.8 Transportation Sector Projections to 2010 and 2015 High-Efficiency/Low-Carbon Scenaro (Continued)

	1997	2015		Change v. BAU	
	BAU	BAU	HE/LC	Change	% Change
Energy Use (quads)	25.5	34.0	26.7	-7.3	-21%
Carbon Emissions (MMtC/Yr.)	487	646	484	-162	-25%
Passenger Cars	171	192	134	-58	-30%
Light Trucks	113	174	114	-59	-34%
Other Modes	203	280	236	-44	-16%
Fuel Use by Fuel Type (quads)					
Motor Gasoline	15.1	18.7	11.2	-7.5	-40%
Cellulosic Ethanol (in motor gasoline)	0.0	0.0	0.7	0.7	***
Distillate	4.6	6.0	6.7	0.7	-12%
Jet Fuel	3.6	5.0	4.0	-1.0	-19%
Residual	1.2	1.8	1.8	-0.0	-1%
Other	1.1	2.5	2.2	-0.3	-12%
Energy Use by Mode (quads)					
Light-Duty Vehicles	14.6	19.1	13.8	-5.3	-28%
Passenger Cars	8.8	10.0	7.4	-2.6	-26%
Light Trucks	5.8	9.1	6.4	-2.7	-29%
Freight Trucks	5.6	7.1	6.2	-0.9	-13%
Air	3.6	5.0	4.1	-0.9	-19%
Rail	0.5	0.5	0.4	-0.2	-38%
Marine	1.7	2.5	2.4	-0.0	-1%
Pipeline	0.8	0.9	0.9	0.0	0%
Other	0.2	0.3	0.3	0.0	0%
Energy-efficiency Indicators					
New Car MPG	27.5	27.9	50.2	22.3	80%
New Light Truck MPG	20.5	20.6	37.8	17.2	83%
Light-Duty Fleet MPG	19.6	19.5	27.1	7.6	39%
Aircraft Efficiency (Seat-Miles/Gal.)	51.8	60.6	70.7	10.1	17%
Freight Truck Fleet MPG	5.6	6.1	7.5	1.4	23%
Rail Efficiency (ton-miles/1,000 Btu)	2.7	3.2	4.8	1.6	51%
Transportation Activity Levels (billions)					
Light-duty Vehicle Miles of Travel	2262	2914	2974	60	2%
Freight Truck VMT	173	250	252	2	1%
Commercial Air Seat-Miles	1116	1923	1923	-152	-8%
Rail Ton-Miles	1208	1535	1542	7	0%
Marine Ton-Miles	892	1099	1103	4	0%

Figure 5.7 Sources of Fuel Economy Improvements in High-Efficiency Scenario, 2010

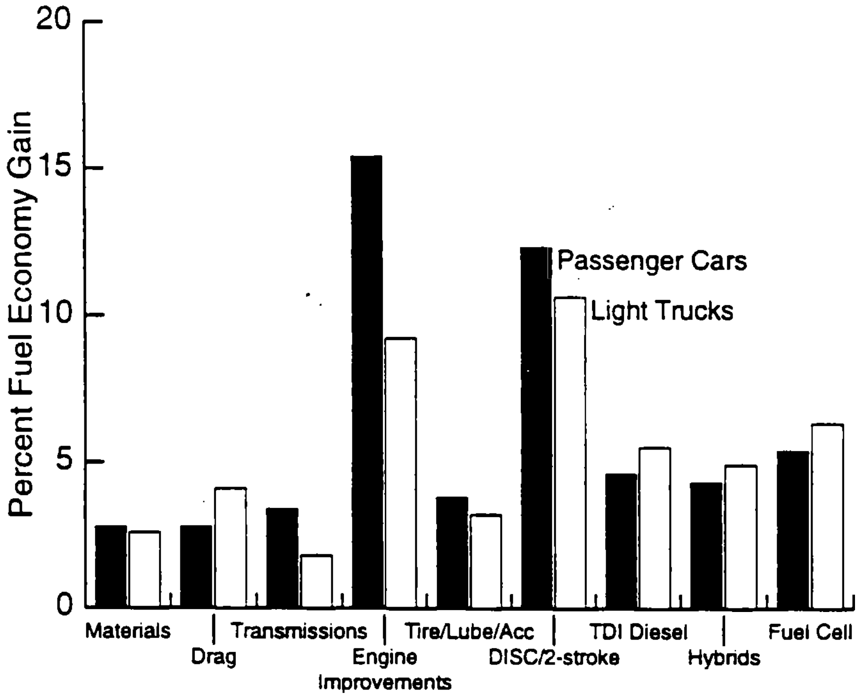
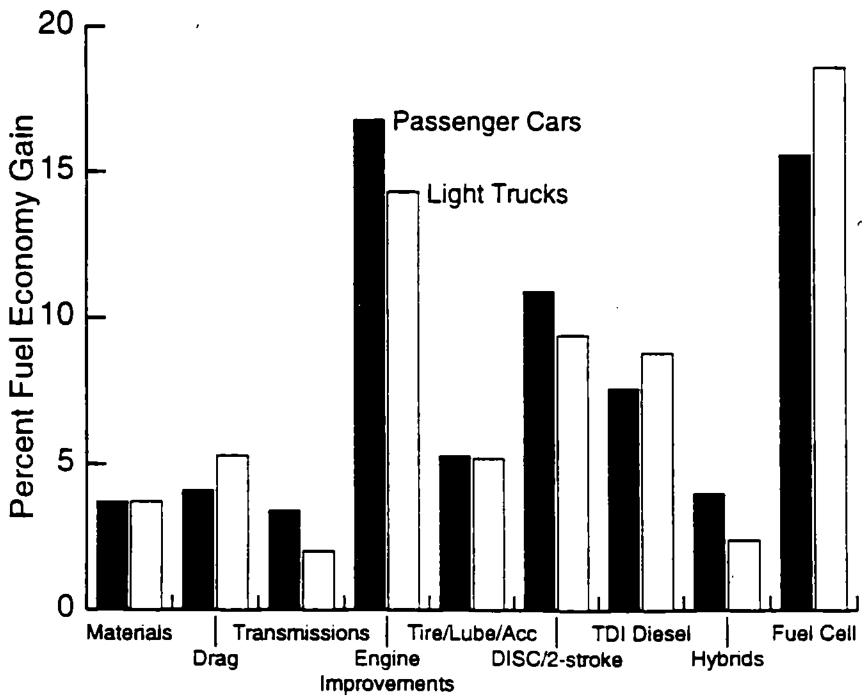


Figure 5.8 Sources of Fuel Economy Improvements in High-Efficiency Scenario, 2015



Transportation activity increases at moderate rates in the business-as-usual case and, indeed, in all the other scenarios as well. Transportation activity in the NEMS model is relatively insensitive to energy prices. In the business-as-usual scenario, light-duty vehicle travel increases by 22% from 1997 to 2010, an average annual rate of just 1.5%. In the high-efficiency/low-carbon scenario, the increase is 24%, reflecting a very small increase due to the lower fuel cost per mile of vehicle travel (1.7%/year). Growth from 2010 to 2015 is slower still, 1.1% per annum. Air travel is the fastest growing mode, with seat-miles growing at 3.4% annually through 2010 and slowing to 2.1% annually from 2010 to 2015. Efficiency improvements in the efficiency and high-efficiency/low-carbon scenarios include increased load factors (passenger-miles per seat-mile) so that seat-miles are actually 7% lower in the efficiency case than in the business-as-usual case in 2010 (Tables 5.7 and 5.8). Freight truck vehicle miles increase at a faster rate than light-duty vehicle miles, 2.5% per year through 2010, slowing to 1.1% from 2010 to 2015. These levels are almost unchanged by further increases in truck freight energy-efficiency. NEMS measures rail and marine activity in ton-miles, and these are up 21% and 17%, respectively, by 2010. Once again, the growth rate from 2010 to 2015 is at the much slower rate of about 1% per year.

The combined effects of moderately increasing transportation activity and significant efficiency gains are still not enough to reduce energy use or carbon emissions below present levels by 2010. Overall, transportation energy use in the business-as-usual case grows from 25.5 quads in 1997 to 32.3 in 2010 and 34.0 in 2015. The efficiency scenario lowers energy use by 9% in 2010 and carbon emissions by an additional 3%, due to the success of cellulosic ethanol as a gasoline blending component. Still, energy use is up 15% over the 1997 level, and carbon emissions are 12% higher. In 2015, however, energy use and carbon emissions are reduced compared to 2010 but still higher than in 1997. Although the 1997 version of the NEMS model does not forecast beyond 2015, it is reasonable to assume that energy use and emissions will continue to fall for a decade or so beyond 2015 as technological improvements penetrate the stock of transportation vehicles.

Motor gasoline use, on the other hand, is only 0.15 quads higher in 2010 than in 1997, and is a full 1.6 quads lower than the current level in 2015. The use of 0.4 quads of cellulosic ethanol and an equivalent shift to diesel are partially responsible for the reduction in gasoline consumption. Because cellulosic ethanol produces almost no net greenhouse gas emissions, it is far more effective than any fossil-based alternative fuel at reducing transportation's carbon emissions. Demand for distillate and jet fuel combined is up 1.7 quads in 2010 and is 2.6 quads higher than the 1997 levels in 2015. The slower growth of gasoline demand suggests a change in refinery operations would be required, but no analysis of the impacts of this change has been made.

The high-efficiency/low-carbon scenario achieves the milestone of reducing CO_2 emissions below 1997 levels, but by 2015 rather than 2010 (Table 5.7). In 2010, CO_2 emissions are 17% (a full 100 MtC per year) below the business-as-usual case, but still 4% above 1997 levels. With new cars at 43 MPG (EPA test value), new light trucks at 31 MPG, and the fleet average at only 27 MPG (23 MPG onroad), efficiency is improving rapidly and still has a long way to go. New passenger car MPG hits a fleet average of 50 in 2015 in this scenario, buoyed by market shares of 25-30% for hybrid vehicles, and 15-20% for turbo-charged direct-injection diesel vehicles. Two-stroke engines are also popular in this scenario, capturing about one-third of the small-car market. By 2015, all remaining new light-duty vehicles are equipped with DISC engines, the gasoline engine of today having been all but entirely squeezed out by newer technologies.

Yet even the high-efficiency/low-carbon case, with its breakthrough technology assumptions, illustrates how much time it takes to fundamentally change the technology of transportation energy use. Though fleet average light-duty vehicle MPG is up from 19.6 to 27.1 (onroad) by 2015, there is another 10.3 MPG to go before the fleet achieves equilibrium with the efficiency of new vehicles. Similarly, in the rail mode, use of fuel cells has penetrated only 5% of the stock of locomotives by

2010 and 15% by 2015. In most cases, the majority of CO_2 emission reductions have yet to be realized, even by 2015. The point is not that little can be done to reduce transportation's CO_2 emissions. The point is that if CO_2 emissions must be reduced, the sooner one gets started, the better.

5.3.5 Cost-Effectiveness of Light-Duty Vehicle Fuel Economy Improvement

The cost-effectiveness of technological changes that improve fuel economy is a very complex issue, depending not merely on the value of fuel savings and the increase in retail price, but on how each technology affects the performance, reliability, appearance and feel of a vehicle. Even such a seemingly simple matter as computing the value of fuel savings is not straightforward, since it depends on car buyers' expectations about future fuel prices, vehicle lifetime (or, alternatively, market valuation of remaining fuel savings when the vehicle is traded in or resold), consumer discounting of future savings, expectations about future depreciation of the vehicle's value, and expected utilization rates.

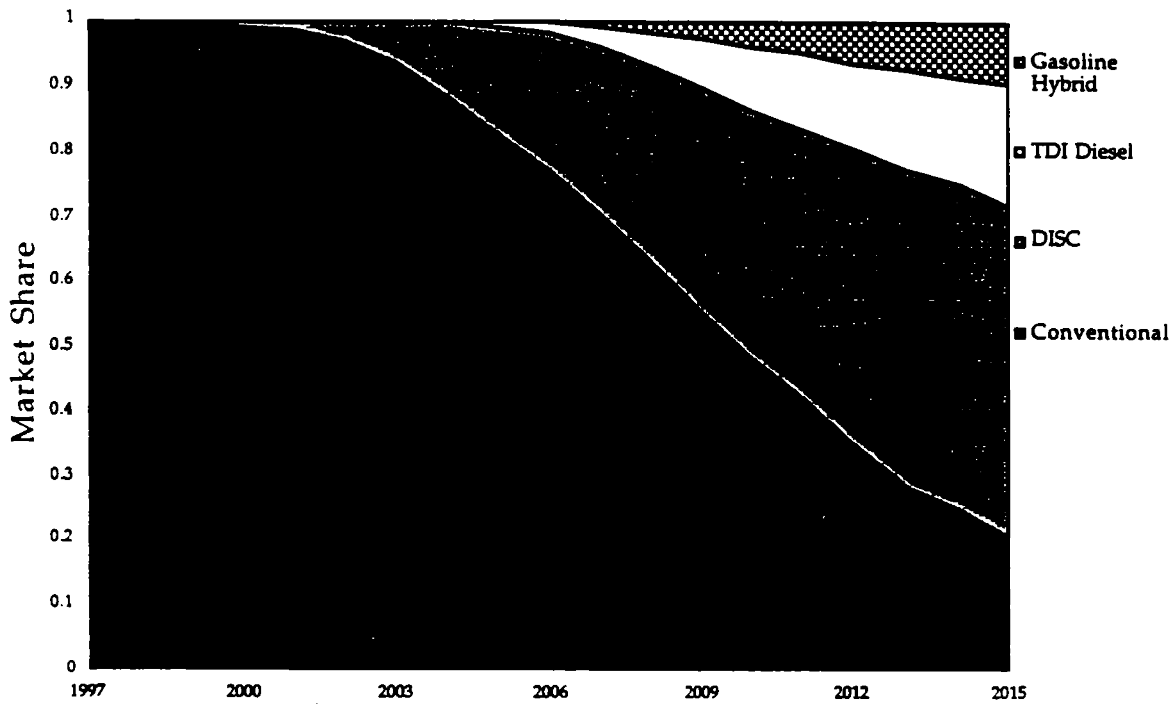
Technological advances are likely to create new opportunities to provide other benefits of importance to car buyers and to society. For example, multi-point fuel injection is generally held to be not cost-effective solely on the basis of fuel savings – yet every new car sold and nearly every new light truck is equipped with it. The reason for including fuel injection is that it improves drivability and also is a critical technology for meeting emissions standards. Technologies included in the efficiency scenarios also have the potential to create social benefits. By reducing oil consumption, they will decrease the volume of U.S. oil imports. By making it easier and cheaper to improve efficiency and substitute alternative energy sources for oil, these technologies will improve U.S. energy security. Technologies such as hybrid vehicles and fuel cells will help vehicles meet increasingly stringent emissions standards. Most importantly, technological advances will be essential to creating a sustainable world transport system.

The cost of supplying technologies is also not a simple matter, since it depends on the rate at which capital equipment must be replaced. If the rate of adoption exceeds the normal rate of turnover of manufacturing equipment, the costs of technological change increase. Also, new technologies must often be certified to meet safety and environmental standards, which takes time and involves some degree of risk. Consumers expect a high degree of reliability of vehicles, and this might be threatened by too rapid introduction of novel technologies.

For all these reasons, the NEMS model does not base technology adoption on a simple cost-effectiveness calculation, but rather attempts to simulate the complex process described above. The market penetration of fuel economy technologies is a function of cost-effectiveness, but is not solely determined by it. Market penetration follow an s-shaped curve that predicts 50% market penetration for precisely cost-effective technologies, with increasing or decreasing market share as cost-effectiveness increases or decreases, respectively. This simulates the fact that consumers are not identical in their valuation of technology (e.g., high mileage drivers such as sales representatives might tend to value fuel economy more than would average drivers), and that technologies have other characteristics that consumers may, or may not, value. Also, introduction is not immediate when cost-effectiveness is reached, but is rather phased in over time, simulating a normal process of retirement and replacement of manufacturing capital.

The phasing in of new technologies can be seen in Figures 5.9 to 5.11, which show the predicted market penetrations of engine technologies. Engine technology penetrations in the efficiency case are shown for passenger cars and light trucks in Figures 5.9 and 5.10. Although the DISC, TDI Diesel, and Gasoline Hybrid technologies eventually come to dominate the market, it takes about a decade for this to occur, allowing time for orderly introduction of the technologies. For comparison, the historical market penetration rates of fuel injection technologies are shown in Figure 5.11. Although it took less time for multi-point fuel injection to replace carburetted fuel systems, this technological change was urged on by emissions regulations. Nonetheless, as a point of comparison, it suggests that the rates predicted by the NEMS model are comparable to similar historical transitions.

Figure 5.9 Market Penetration of Advanced Engines for Domestic Passenger Cars - Efficiency Scenario



For all the reasons noted above, simple cost-effectiveness calculations based solely on incremental first cost and the value of future fuel savings can be misleading. Indeed, the NEMS model outputs do not include direct measures of the costs of technological changes or their value to vehicle purchasers. However, for light-duty vehicles, approximate technology cost estimates can be derived from the market shares of each technology and from the initial cost estimates. By comparing the weighted average cost of fuel economy technology in the efficiency and high-efficiency cases in 2010 with the weighted average cost in 1997 for the BAU case, we can obtain an estimate of the increase in retail price per vehicle due to the adoption of fuel economy technology. The incremental costs must be adjusted, however, to reflect the fact that a significant fraction of the potential MPG increase is used in the NEMS model to produce higher horsepower or increased vehicle weight, or to offset small MPG losses due to safety and emissions improvements. The cost adjustment is made by multiplying the full cost increase by the ratio of the actual MPG gain to the potential MPG. For example, for automobiles in the efficiency case, this ratio is 0.7. Using the same assumptions employed in the model to calculate cost-effectiveness, we can also estimate the value to the average consumer of the change in fuel economy. These estimates are summarized in Table 5.9.

Figure 5.10 Market Penetration of Advanced Engines for Domestic Light Trucks - Efficiency Scenario

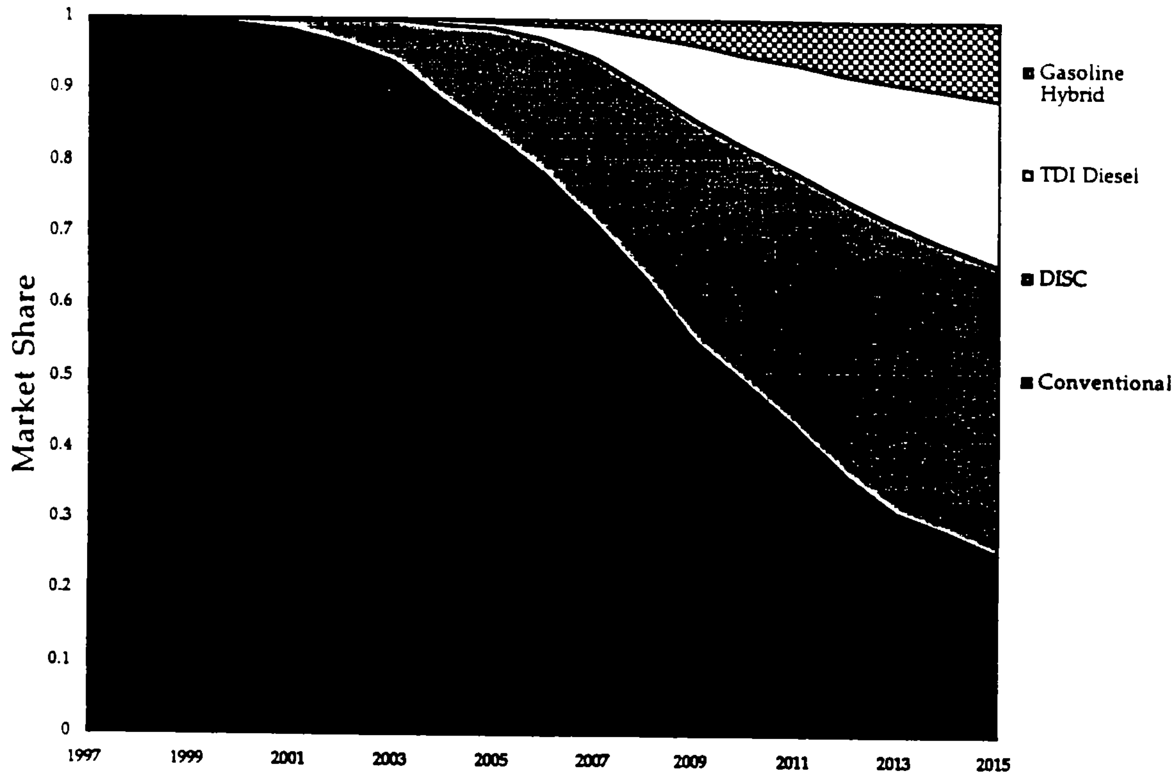


Figure 5.11 Penetration of Fuel Injection Technology

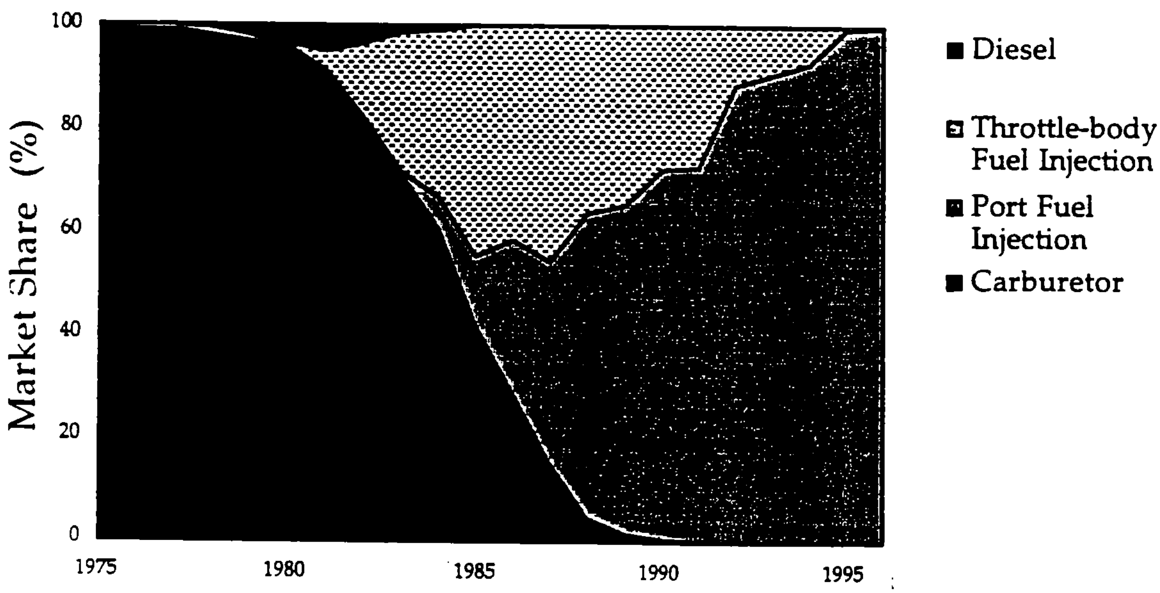


Table 5.9 Simple, Total Cost-Effectiveness Estimates for Light-Duty Vehicle Fuel Economy Technology

				Value of Fuel Savings to Consumer	
Scenario	MPG	Full Incremental Cost	Adjusted* Incremental Cost	10% Implicit Discount Rate	20% Implicit Discount Rate
Passenger Cars					
Business as Usual	27.5	$0	$0	–	–
Efficiency	37.5	$850	$600	$1,600	$1,000
HE/LC	43.1	$900	$900	$2,150	$1,350
Light Trucks					
Business as Usual	20.5	$0	$0	–	–
Efficiency	27.1	$800	$650	$1,950	$1,200
HE/LC	30.8	$950	$900	$2,700	$1,700

Gasoline prices assumed to remain constant at $1.20 per gallon. Vehicle usage rate of 15,500 miles per year, declining with vehicle age at 4% per year, and lifetime of 14 years. For calculating value to consumers, MPG estimates are reduced by 15% to reflect actual operating conditions.

*Adjusted to account for the use of fuel economy technology to increase horsepower instead of increasing miles per gallon. The cost effectiveness estimates in Table 5.9 show that even at the higher 20% implicit discount rate, the light-duty vehicle fuel economy improvements are, as a whole, cost effective. This is not surprising since the NEMS model bases its technology market penetration predictions on a similar measure of cost effectiveness. Discounting future fuel savings at a lower rate of 10% only improves cost effectiveness.

Based on a simple comparison of incremental vehicle costs to the value of fuel savings to the consumer, fuel economy improvements in the efficiency scenarios appear to be cost-effective as a whole. Savings exceed costs for both discounting formulas shown. Choosing the correct discount rate is somewhat controversial since it depends on whether one believes that there are imperfections in the market for fuel economy. In the buildings chapter, for example, a 7% real rate is used to discount future fuel savings. We believe that a 20% implicit discount rate should be used for valuing light-duty vehicle fuel economy savings for the following reasons. When a consumer invests in vehicle technology to improve fuel economy, his or her decision-making calculus is analogous to a firm's capital investment decision. Indeed, consumers can be though of as producing their own vehicle travel with inputs of vehicles, materials, and labor. In making this decision, the consumer must not only consider his or her discount rate (time preference or opportunity cost for money) but also the depreciation of capital. In other words, there are two costs of capital that must be accounted for, the time cost of money tied up in the capital and the depreciation of the capital. In general, the depreciation in a car's value is much greater during the first few years of its life. Indeed, a very significant depreciation occurs instantaneously when the first owner takes over possession from the dealer. After that time, the car is no longer "new". The initial owners of vehicles tend to hold them for about four years, on average, so that they bear a disproportionate share of the cost of depreciation.

The tendency of used car markets to "bundle" vehicle attributes, rather than price each separately may create a market imperfection that, when combined with the greater depreciation in value during the first few years of ownership, implies that new car buyers may reasonably be expected to demand a high rate of return in fuel savings for an investment in fuel economy technology. According to this hypothesis, with the exception of a few highly visible items, used car prices are determined by initial prices and the average rate of depreciation. That is, the value of fuel economy in the used car market is determined not so much by the present value of future fuel savings, as by the depreciated value of the initial investment in fuel economy. Assuming this market imperfection exists, the cost to the new car buyer of an investment in fuel economy technology is determined by the depreciation in its value over the first four years, rather than by the consumption of its fuel savings potential.

The combination of these two factors may lead new vehicle buyers to demand a rate of return much higher than the simple discount rate. If one assumes a 20% depreciation during the first year of vehicle ownership and 10%/yr. thereafter, then a consumer with a 7% real discount rate would, in effect, discount the full 14 years of fuel savings at about 15% to16% to compensate for the cost of depreciation during the first four years of ownership. If future fuel savings are computed using the average usage rate for new vehicles, then future savings must be further discounted by 4% to 5% per year to reflect the typical rate of decline in vehicle use with age. Taken together, these factors imply that a new car buyer may appear to behave as if his discount rate for valuing future fuel savings were 20%, when in fact his simple real discount rate is only 7%.

These rough estimates should be treated with considerable caution. First, they represent a comparison of total costs of fuel economy changes with total benefits, taxes included, rather than the more correct comparison of marginal costs and benefits, excluding taxes. Markets will, in theory, stop improving fuel economy when the marginal costs equal the marginal benefits. In general, this will be at a lower level of fuel economy than the point at which total costs equal total benefits. Second, the NEMS model represents technology adoption as a more complex process than a simple computation of monetary costs and benefits, and attempts to simulate actual market behavior. Thus, the calculations reported above do not correspond to the NEMS technology adoption methodology.

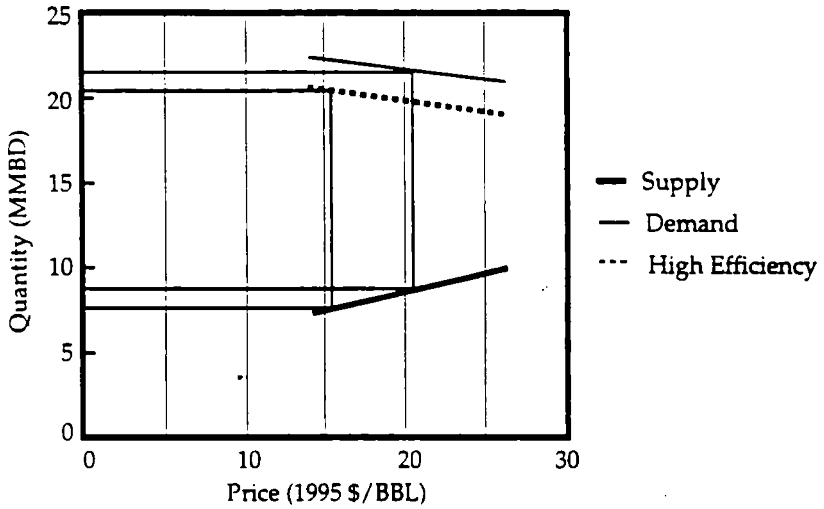
5.3.6 Oil Imports and Oil Market Benefits

The reductions in energy use achieved in the efficiency and high-efficiency/low carbon scenarios represent significant reductions in U.S. petroleum demand which should result in reduced U.S. oil import dependence and lower oil prices to consumers. Because of transportation's continuing dependence on petroleum in the business-as-usual scenario, 95% of transportation energy is still derived from petroleum in 2010. In the BAU scenario, transportation uses 30.6 quads (14.5 million metric barrels per day (MMBD)) of petroleum products. Technological advances contained in the efficiency scenario reduce petroleum consumption by 3.4 quads (1.6 MMBD) in 2010, and those in the high-efficiency/low-carbon scenario produce total oil savings of 4.9 quads (2.3 MMBD).

Lower U.S. oil consumption due to more energy-efficient technology and substitution of cellulosic ethanol should reduce U.S. oil imports, or reduce world oil prices, or both. The exact world oil market response is indeterminate because it depends on the actions of the OPEC cartel. In a competitive world oil market, the response to reduced U.S. demand could be predicted based on knowledge of the U.S. and rest-of-world supply and demand curves for oil. But because the cartel's supply does not necessarily follow the rules of competitive market behavior there is, in effect, no OPEC oil supply curve. Faced with reduced demand, competitive producers would lower prices, encouraging demand and driving out the higher cost producers until a new equilibrium were reached. But a cartel can choose to cut production, raise production, or do nothing, making the ultimate outcome uncertain. Cutting production would raise world oil prices but the cost to OPEC would be loss of market share, a key determinant of market power.

No matter what the OPEC cartel chose to do, however, either U.S. imports would fall, or oil prices would fall, or both, as a result of the technological advances reflected in the efficiency and high-efficiency/low-carbon scenarios. This is illustrated in Figure 5.12, which shows U.S. long-run supply and demand curves for petroleum derived from the 1997 Annual Energy Outlook's Low, High, and Reference Oil Price Cases for 2010 (EIA, 1996b, Table C11). The curves clearly show that at the reference case oil price of $20.41 per barrel, domestic supply and demand curves do not intersect, with the result that the 12.9 MMBD shortfall must be imported.

Figure 5.12 U. S. Oil Supply and Demand in 2010



The advanced technologies of the high-efficiency/low-carbon scenario shift the demand curve towards lower demand, and may also change its slope (perhaps making demand more responsive to price). If we assume that the world price of oil does not change (to achieve this result, OPEC would have to cut production by an amount roughly equivalent to the reduction in U.S. consumption), then U.S. imports would be lower by about 2 MMBD. If OPEC maintains previous production levels or increases its output, world oil prices would fall. As prices fall, U.S. domestic supply will decline and demand will increase, pushing imports back up. However, to achieve the original level of imports (12.9 MMBD), prices would have to fall by about $5 per barrel (given the supply and demand curves shown in Figure 5.12). The $5/bbl. price cut would reduce the total cost of oil to the economy by about $35 billion, and reduce the cost of oil imports by about $20 billion, in comparison to the AEO97 reference case. The possible outcomes are: 1) U.S. imports are reduced by 2.3 MMBD or more, 2) world oil prices fall by about $5/bbl or more, or 3) a combination of reduced imports of up to 2.3 MMBD and a price decrease of up to $5/bbl. occurs.

5.4 R&D POTENTIAL FOR ADVANCED TECHNOLOGIES IN 2020

5.4.1 Light-Duty Vehicles

Many of the advanced technologies that have the potential to impact U.S. automotive fuel use after 2010 or 2020 need considerable research and development work before they can attain commercialization. The federal government has supported work on many of these technologies for more than 20 years, beginning with the Energy Policy and Conservation Act of 1975. The current U.S. R&D effort on the more exotic of the new technologies has been characterized as "the most comprehensive, best organized, and best funded in the world" (U.S. Congress, OTA, 1995). Nevertheless, over the years, federal funding for vehicle technology R&D has been erratic, and there are continuing budget battles over funding for DOE's Electric and Hybrid Vehicle Program and the PNGV as a whole. As noted above, the National Research Council Committee that is reviewing the PNGV program has stated in no uncertain terms that they believe the program is seriously under-funded relative to its ambitious goals.

The OTA identified several R&D areas that will require considerable new resources including: safety; analysis and development of infrastructure for manufacturing, refueling, servicing, recycling, and so forth; and development of new standards for new materials and fuels (U.S. Congress, OTA, 1995). Also, OTA concluded that the current federal program may not take appropriate advantage of the innovative capabilities of small business, especially with budget pressure on the National Institute of Science and Technology's Advanced Technology Program and other R&D efforts that focus on smaller companies.

Although there are many hurdles to overcome, a strong R&D effort coupled with a market or regulatory incentive to improve fuel economy should be capable of producing, by 2020 or earlier, mid-sized vehicles with fuel economies in the 60-80 MPG range and performance similar to current vehicles – that is, "PNGV territory." Note that continuing fleet increases in power and performance will tend to reduce future fuel economy potential, since generally there is a direct tradeoff between performance and fuel economy. An optimistic vision of a potential high-efficiency/low-carbon vehicle in 2020, assuming the necessary breakthroughs in a number of areas (e.g., manufacturing processes for composite materials, two orders of magnitude reduction in fuel cell costs) would combine the following characteristics:

- Highly aerodynamic design with C_d of 0.22 or below;
- Lightweight body with composite body structure (safer alternative: optimized aluminum);
- Ultra-low rolling resistance tires, CR of 0.005 (about half that of today's tires);
- Hybrid drivetrain with lightweight, highly efficient storage device (ultracapacitor or flywheel) and electric motor/controller;
- Fuel cell powerplant with advanced hydrogen storage or efficient fuel reformer (safer alternatives: DISC engine or DI diesel with lean NO_x catalysts); and
- Use of high-efficiency/low-carbon accessories and low-energy-use design (e.g., advanced window coatings and insulation).

The current PNGV program is addressing many of the remaining R&D roadblocks though some need considerably more attention and the solution to others might be accelerated with greater resources. For example, development of manufacturing processes for composites has been hit hard by budget cutbacks; as noted, without major breakthroughs, composites will likely be too expensive to play a major role in vehicle light-weighting. In addition, there is some concern that Japanese and European firms are devoting more resources to DISC and DI diesel engines than are U.S. companies, and these engines may play a critical role in future high-efficiency/low-carbon vehicles, especially if fuel cell development is delayed or is unsuccessful at reducing costs sufficiently for commercialization.

Fuel cells are widely believed to be the most attractive powerplant option for future vehicles, and recent progress in increasing their power density and lowering costs through reducing their platinum requirements has been extremely promising. Nevertheless, as discussed previously, many hurdles remain, and their costs must decline remarkably for them to compete successfully with internal combustion engines. In fact, they would revolutionize the power generation industry long before they reached the $30/kW level of ICEs.[13]

Although some may view a fuel cell hybrid vehicle as an "ideal" vehicle, there are sufficient uncertainties in the potential of the technologies needed for such a vehicle, and sufficient heterogeneity in regional requirements and markets, to imply that an ideal R&D program in light-duty vehicle technologies should be a broad program incorporating a range of alternative technology pathways to high vehicle efficiency and low emissions. A breakthrough in high-specific-energy battery technology coupled with significant progress in electric motors and power electronics, for example, could put large numbers of efficient electric vehicles into many urban markets; in some of those markets (e.g., California) both the overall emissions effects and the greenhouse gas emissions effects could be extremely positive. Similarly, breakthroughs in on-board storage technology for natural gas might allow substantial penetration of natural gas vehicles into many markets, although the positive greenhouse gas emissions impact of such vehicles would likely be substantially less than for EVs or fuel cell hybrids.

5.4.2 Freight Trucks and Locomotives

The diesel cycle engine will dominate the freight truck sector at least until 2020 because of its high thermal efficiency, potential fuel flexibility, and durability. DOE's Office of Heavy Vehicle Technologies (OHVT) within the Office of Transportation Technologies is attempting to develop the enabling technologies needed to achieve fuel flexibility, ultra-low emissions, and high fuel efficiency in all classes of trucks, buses, and other heavy vehicles such as off-highway vehicles. The typical new Class 8 tractor trailer in 2020 is expected to achieve an on-road fuel economy of over 10 MPG, compared to about 7 MPG today, assuming a high-efficiency/low-carbon, low emission diesel cycle engine (thermal efficiency of at least 55% at rated speed and load at the flywheel) and other technologies such as reduced aerodynamic drag, low rolling resistance tires, and lightweight materials (such as magnesium) become an economic reality.[14] While many of these technologies have already been demonstrated to a limited extent, a key enabler is a durable highly efficient NO_X catalyst capable of operating at high-efficiency/low-carbon in an oxidizing atmosphere.[15] Fuel reformulation is envisioned, as well as nonpetroleum fuels, during this period (2000-2020).

However, as the efficiency of the diesel cycle becomes fully exploited (thermal efficiencies of over 63% will be highly unlikely), the hydrogen fuel cell, unconstrained by the Carnot cycle, may be the next powerplant of choice for freight trucks, locomotives, and passenger cars. Significant R&D efforts at DOE have enabled the demonstration of methanol-fueled fuel cell buses and other vehicles. However, significant development of the fuel cell itself, power management strategies, and hydrogen fuel production, distribution and storage are required, and economical solutions are hard to envision before 2020. Particularly problematic are the low cost, efficient production, delivery, and storage of hydrogen fuel (carbon-containing fuels significantly degrade fuel cell thermal efficiency – in many cases to efficiencies below that of current-production diesel engines). The fuel cell powerplant, combined with low aerodynamic drag, low rolling resistance tires, and lightweight materials may raise Class 8 tractor trailer fuel efficiency to 15 MPG or more. Locomotive engines may be an ideal test bed and an early entry for fuel cell powerplant technologies, because sizes needed (4000 hp-equivalent) are on the scale of smaller stationary electrical power generation plants which are already commercial. In addition, locomotives are already driven by computer-driven electric motors for traction control.

5.5 SUMMARY

Cost-effective or near cost-effective technologies and alternative energy sources have the potential to significantly restrain the growth of the U.S. transportation sector's greenhouse gas emissions through 2010. There remains a substantial reservoir of proven technology for improving motor vehicle fuel economy, and technologies that are very nearly market-ready (such as the DISC engine with lean-NO_X catalytic converter) will almost certainly further expand the potential to increase MPG by 2010. New technologies and operational efficiency gains hold out similar potential for air passenger travel and for truck and rail freight. Ethanol derived from cellulosic feed stocks instead of grain could also make a significant contribution by 2010 as a blending component for conventional gasoline if cost reductions foreseen by energy researchers are achieved. Overall, the combined impact of such technologies could be to reduce greenhouse gas emissions by 10% in 2010 and by almost

20% in 2015, relative to the business-as-usual case. If important breakthroughs can be achieved in fuel cells and other key technologies, transportation's greenhouse gas emissions in 2015 could be held below current levels.

In the business-as-usual case, transportation energy use grows from 25.5 quads in 1997 to 32.3 in 2010 and 34.0 in 2015. Carbon dioxide emissions, in million tonnes of carbon, increase from 487 in 1997 to 616 in 2010, and to 646 in 2015. As mentioned earlier, the business-as-usual case anticipates rates of growth in transportation activity that are slow by historical standards. The actual outcome could easily be 10% higher. The efficiency case holds transportation energy use to 29.3 quads in 2010 and 28.7 in 2015. Accordingly, carbon emissions grow to only 543 MtC in 2010 and 532 in 2015. The fact that emissions are lower in 2015 than in 2010 reflects the fact that changing the technology of transportation energy use requires the orderly turnover of durable capital stock. The high-efficiency/low-carbon scenario holds 2010 carbon emissions from transport to 512 MtC, and reduces 2015 emissions to 484 MtC, just slightly below the 1997 level.

Changes in the mix of transportation fuels in the three 2010 scenarios are summarized in Table 5.10. Although petroleum fuels are still the predominant source of energy for transportation, use of alternative fuels expands in all three scenarios. Natural gas consumption for transport grows from 0.75 TCF in 1997 (about 98% of which is used in natural gas pipelines) to roughly 1.2 TCF in 2010. In 2010 pipelines still account for 70-75% of natural gas use, but CNG vehicles consume about 0.25 TCF, and natural gas used to produce methanol for motor fuel accounts for nearly all of the rest. Biofuels in the form of cellulosic ethanol come on strong in the efficiency and high-efficiency/low-carbon scenarios, providing from one-fourth to one-third of an MMBD oil equivalent. In accord with the AEO97 reference case projections, all scenarios foresee substantial increase in electricity use, essentially all going to electric vehicles. The lower levels of electricity use in the efficiency and high-efficiency/low-carbon scenarios, like those of natural gas use, are due to the general improvements in vehicle technology in those scenarios.

Table 5.10 Transportation Energy Use by Fuel Type

Fuel	1997	2010		
		BAU	Efficiency	High-Efficiency
Petroleum Fuels (MMBD)	11.77	14.59	12.91	12.18
Natural Gas (TCF)	0.75	1.22	1.19	1.16
Biofuels (MMBD OE)	0.001	0.04	0.25	0.34
Electricity (MMBD OE)	0.04	0.23	0.22	0.20

Note: Petroleum fuels converted to million barrels per day oil equivalent using a heat content of 5.738 MMBtu/barrel. Natural gas includes pipeline fuel and natural gas used to produce methanol for use as a neat fuel, but does not include natural gas used to produce methanol for use in Methyl Tertiary Butyl Ether. It is assumed that, to produce one quad of methanol, 1.44 quads of natural gas are required. For electricity generation, 3.38 quads of primary energy are assumed to be required for each quad of electrical energy consumed.

Carbon emissions by mode are summarized in Table 5.11. Light-duty vehicles account for the vast majority of carbon emissions reductions versus the business-as-usual case, with significant contributions also being made by trucks and commercial aircraft. Rail freight shows the greatest relative reduction, while emissions from shipping, military and "other" are essentially constant across the three scenarios.

Table 5.11 Carbon Emissions in 2010 (MtC)

		2010		
	1997	BAU	Efficiency	High-Efficiency
Light-Duty Vehicles	278.7	346.3	297.3	273.0
Freight Trucks	73.3	95.0	83.4	80.9
Freight Rail	8.9	9.6	8.1	7.1
Shipping	30.8	42.7	42.3	41.6
Air Transport	60.0	83.5	72.9	69.6
Military, Transit, Other	35.3	39.0	39.3	39.3
TOTAL	486.9	615.9	543.3	511.5

Note: Breakdown into modal carbon emissions based on emissions factors taken from EIA (1996d) and DOE (1996)

Most of the reduction in energy use and carbon emissions comes from light-duty highway vehicles. There are four reasons for this. First, light-duty vehicle technology has been far more intensively studied, so that a great deal more is known about the technological potential for this mode. Second, the level of expenditure on technology R&D is greatest for this mode, with the possible exception of aerospace R&D, including defense aerospace. Third, the commercial modes are believed to be more sensitive to fuel costs and more aggressive in the adoption of energy-efficient technology. Therefore, the rates of energy-efficiency improvement in the business-as-usual case are higher for these modes. Finally, light-duty vehicles simply use more energy than any other mode: 60% in the business-as-usual case. The other modes cannot be ignored, however, and should probably be given much greater attention with respect to R&D investment.

Although technological improvements have the potential to cost-effectively restrain greenhouse gas emissions from transportation, it is not likely that the changes will come about without a major public policy initiative. There are two reasons for this. First, the problems posed by greenhouse gas emissions are what economists term a classical public good externality. This means that the market economy will not provide the right price signals either for the development or the adoption of low-carbon technologies. Second, the AEO97 projections foresee a world where fossil fuels are abundant, available and inexpensive. In particular, none of the oil market upheavals of the past quarter century are present in the forecast. As a result, there are no other economic incentives to encourage either energy-efficiency or alternative fuels. In such an environment, it is not reasonable to expect either that appropriate technology will be developed or that success in the marketplace will result.

As a result, the efficiency case is based on the assumption that policies are implemented to promote the development of cost-effective low-carbon technologies and to spur the adoption of these technologies. In our view, this would include at a minimum a greatly increased public sector investment in R&D addressing energy-efficient and low greenhouse gas technologies, perhaps two to ten times the current level of effort. There are other public interests in developing such technologies (e.g., energy security and environmental sustainability) that, we believe, could easily justify such a level of investment. But policies to insure the adoption of low-carbon technologies in the market would also be necessary. It is not the purpose of this study to recommend what those policies should be; nonetheless, we are obliged to point out that meaningful policies will be necessary.

Indeed, technology has enormous potential to reduce transportation's greenhouse gas emissions. Cost-effective technological change will take time however, and its full effects will not be felt for two decades or more. Because the problems that may result from increased carbon emissions affect the global environment, significant reductions will demand meaningful public policy initiatives. These must include a greater effort to develop low-carbon technologies and a commitment to implement policies that will insure their adoption in the market.

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ENDNOTES

[1] This rate applies to the period 1973 (18.605 trillion Btus) to 1985 (20.067 trillion Btus). Source is Table 2.2, Monthly Energy Review, April 1997, DOE/EIA-0035(97/04), U.S. Department of Energy, Energy Information Administration, Washington, DC.

[2] This is a summary report. The full report, which presents this material, was not published due to OTA's closure, but it is now available as part of a three-CD set that contains all of OTA's reports since its inception. U.S. Congress, Office of Technology Assessment, *OTA Legacy: 1972 through 1995,* U.S. Government Printing Office, Washington, DC, Stock no. 052-003-01457-2, $23 U.S.

[3] The Toyota AXV5, with a C_d of 0.20, appears to avoid sacrifices in interior and cargo space. Removing its wheel skirts, which might inhibit maintenance and restrict the vehicle's turning circle, would likely raise its C_d to about 0.22. Because the vehicle's underbody cover adds weight, the net positive effect on fuel economy will be reduced somewhat (U.S. Congress, OTA, 1995).

[4] In particular, requirements for 0-60 mph acceleration and sustained gradeability.

[5] Also referred to as compression ignition direct injection (CIDI) engines and turbocharged direct injection (TDI) diesel engines.

[6] An accurate cost comparison would have to account for the transmission needed by the engine versus the electric motor needed to convert the fuel cell's output electricity into shaft power. Also, the fuel cell drivetrain may need a powerful battery to drive the vehicle until the cell can warm up.

[7] At about 3700 psi storage pressure, storage volume for hydrogen is about 5 times that needed for gasoline (Oei, 1997).

[8] An additional cost may be the loss in system efficiency associated with onboard reforming as well as the original refining of the gasoline. However, onboard hydrogen storage has energy costs in the form of hydrogen production (probably at a large scale, and more efficient than the onboard reformer) and pressurization if stored in high pressure tanks.

[9] Despite what is implied in the NEMS Transportation Model documentation, we were informed by Mr. David Chien, principal in charge of the Transportation Model, that the model's calculations were in 1987$. Thus, $8 in 1995 dollars equates to approximately $6 in 1987 dollars.

[10] For carbon only; or $.08-$0.16 per gallon if the tax applies to all greenhouse gases, on a carbon equivalent basis.

[11] Communication from Margaret Singh of Argonne National Laboratory, April 3, 1997. Her calculations were made using the August, 1993 version of M. A. Delucchi's greenhouse gas emissions model and exclude any vehicle efficiency gains which might occur with the use of an ethanol vehicle.

[12] An alternative approach would have been to introduce these technologies using the Transportation Model's alternative fuel vehicle capabilities. This approach was not taken on the grounds that diesel is more conventional than an alternative fuel. Consumers are familiar with it, it is widely available and, especially for the advanced, clean, TDI technology considered here, its performance would be essentially identical to that of a gasoline vehicle.

[13] Actually, for an accurate comparison, an ICE plus a transmission and inexpensive fuel tank should be compared with a fuel cell, hydrogen storage or liquid fuel storage/reformer system, battery for warmup power and power buffer, and electric traction motor, making the task of commercializing fuel cells all the more onerous.

[14] The Class 8 truck is very efficient already. Considering an energy per ton-mile measure of performance, an equivalent passenger car needs to travel about 140 miles on a gallon of gas to be as efficient as a 7 MPG Class 8 truck.

[15] This technology is required for direct-injection gasoline engines as well.

Chapter 6

THE ELECTRICITY SECTOR'S RESPONSE TO END-USE EFFICIENCY CHANGES

6.1 INTRODUCTION

Electricity consumption accounts for about 36% of both total primary energy consumption and carbon emissions in the United States (EIA 1996a). As a consequence, converting efficiency-induced electricity savings in the residential, commercial, and industrial sectors into carbon reductions is a critical part of this study.

This task is complicated by several factors. First, the U.S. electricity industry is in the midst of a major restructuring, from a highly regulated, vertically integrated industry to a largely competitive, deintegrated industry. Because this transformation is far from complete, it is difficult to predict the structure and operation characteristics of electricity markets for the year 2010. Second, electricity production in the year 2010 will depend on the generating units that are retired, repowered, and constructed between now and then, as well as on how those units are operated in 2010. The decisions made by the profit-maximizing owners of individual generating units are likely to be different than the cost-minimizing decisions made in the past by utility owners of large generation and transmission systems. As a result of these changing dynamics of capacity expansion and system operation, one cannot assume that the average and marginal carbon intensities of electricity use (tonnes of carbon/GWh) will be the same in 2010 as they are today. Indeed, they are likely to be quite different. Third, electricity prices in the year 2010 are likely to vary from hour to hour based on current spot-market prices; consumer response to such time-varying prices is likely to be substantial but is largely unknown.

The next section describes some of the key changes in the structure of the U.S. bulk-power system that are likely to occur over the next decade. Section 6.3 describes the Oak Ridge Competitive Electricity Dispatch (ORCED) model that is used here to project the characteristics of the electricity sector in the year 2010. Section 6.4 compares ORCED's projections for the electricity sector with those developed by EIA in its *Annual Energy Outlook 1997* (AEO97). We then develop a competitive-electricity market case for 2010, which is used as the base case against which the efficiency and high-efficiency/low-carbon cases are compared.

6.2 BACKGROUND

In response to the 1992 Energy Policy Act, the Federal Energy Regulatory Commission (FERC) issued a major order (Order 888) in April 1996, which it slightly revised in March 1997. This order requires utilities to unbundle their generation and transmission services. A utility cannot offer preferential transmission pricing for electricity generated by its own power plants. A key purpose of this order is to eliminate problems associated with vertical market power in bulk-power markets and thereby assure open access to the nation's transmission facilities.

Other factors are also forcing the U.S. electricity industry to change. These factors include low natural gas prices (both today and over the next 10 to 15 years), substantial improvements in the efficiency of gas-fired combustion turbines, and broad public sentiment to deregulate economic sectors wherever possible.

We see a future in which the generation sector will be driven primarily by competitive forces rather than by regulatory mandates. Decisions on whether, when, and where to build, repower, or retire generating units will be made by investors, not by regulators.[1] Historically, vertically integrated utilities have planned, built, and operated power plants to minimize the life-cycle costs of the entire electric-power system over a long time (e.g., 20- to 30-year horizon). In tomorrow's competitive environment, this decision rule will be replaced by one that emphasizes the profitability of individual generating units over a much shorter time horizon, using a higher discount rate to reflect the increased riskiness of power-plant ownership.

Our view of the future calls for most of today's utility-operated control centers to be replaced by *independent* system operators (ISOs) that cover larger areas. As a consequence, the number of control areas will decline from about 140 to perhaps only 20 to 50. Because these ISOs perform a monopoly function, they will be regulated by FERC.

Similarly, transmission will remain a monopoly function, also regulated by FERC. Increasingly, transmission will be separated from generation. Today, FERC requires utilities to "functionally" unbundle generation from transmission. In the future, utilities will increasingly divest themselves of their generation assets and will become "pure" transmission or transmission-plus-distribution utilities. In this environment, transmission will become a common carrier.

6.3 MODEL DESCRIPTION

ORCED is an expanded version of part of a previously developed model called ORFIN (Oak Ridge Financial Model) (Hadley 1996). Whereas ORFIN is a comprehensive electric-utility planning model, ORCED deals only with generation. We developed ORCED to aid in the analysis of the operation of competitive (as opposed to the traditional regulated) bulk-power markets. The model allows the following issues to be examined:

- Horizontal market power: concentration of generation assets among a few owners;
- Generator profitability: which units will be retired because their expected revenues will not cover the sum of their fuel costs, variable operations and maintenance (O&M) costs, and (avoidable) fixed O&M costs, as well as repowering and new construction decisions;
- Carbon emissions and other environmental effects of changes in the U.S. bulk-power sector; and
- Optimal mix of new and existing generators, including new generating technologies.

The model is structured to allow simulation of different bulk-power market structures. In particular, the user can specify various generation pricing schemes:

- An energy-only spot price as proposed by the three California investor-owned electric utilities. When unconstrained demand exceeds available supply, what would otherwise be unserved energy is "curtailed" because spot prices rise sufficiently to suppress demand to match the level of available generating capacity. The user simulates this situation by specifying a value for the price elasticity of demand during these time periods. ORCED uses the amount of demand to be curtailed and the price elasticity to calculate the value of unserved energy in ¢/kWh.[2]
- An energy-only spot price plus the loss-of-load probability (capacity) component used in the United Kingdom. Here, the user specifies a value for unserved energy (e.g., 200¢/kWh), which

the model multiplies by the hourly value of the loss-of-load probability to produce a time-varying increment to the energy-only spot price.

- An energy-only spot price plus a capacity reservation price (in $/kW-year), as proposed by the PJM Interconnection and the New England Power Pool. In this case, the user specifies an amount of generating capacity needed for planning reserve, which determines the annual capacity payments (in $/kW-year) required.

We are using ORCED to examine the issues listed above as functions of the following factors (in addition to the pricing schemes noted above):

- Characteristics of individual generators: type of unit, differences in capital and other fixed costs ($/kW-year) vs. fuel and variable O&M costs (¢/kWh), dispatchability (e.g., fully dispatchable coal plant vs. must-run nuclear unit vs. stochastic wind plant), forced and planned outage rates (%).

- Customer and load characteristics: shape of load curve, price elasticities of demand, value of unserved energy.

- Generating-resource portfolio: mix of generating units and relationship between available generating capacity and unconstrained peak demand.

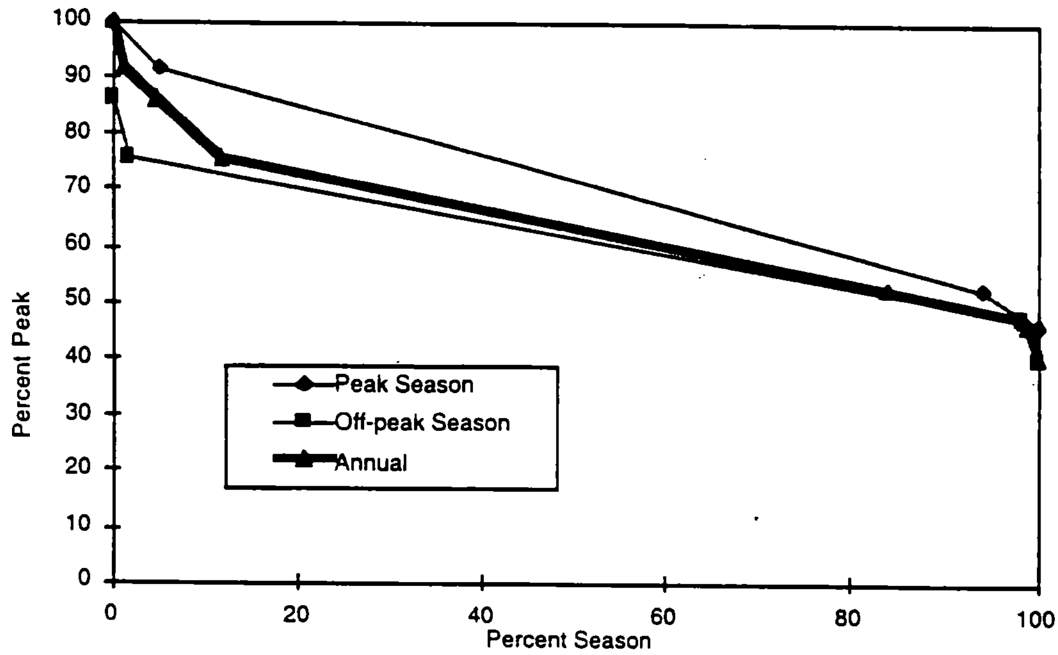
ORCED includes a production-costing model that uses load-duration curves rather than chronological loads as inputs. The model is run twice for each year of simulation, once for an on-peak season and a second time for an off-peak season (Figure 6.1). We define the on-peak season as June through August, and the off-peak season as the remaining nine months (September through May), although the model can accept alternative definitions of the two seasons. The model can incorporate disaggregate inputs on loads and load shapes for the residential, commercial, and industrial customer classes. Data on these class loads are aggregated for use within ORCED, which builds and dispatches generating units to meet aggregate load.

A load-duration curve is created by ordering demand (in MW) in terms of magnitude from highest to lowest. The resultant curve shows the percentage of time that demand exceeds a particular value, ranging from the one-hour peak demand down to the minimum demand.

Use of a load-duration curve to calculate production costs is much simpler and computationally much less burdensome than use of chronological loads (i.e., hour by hour loads). This simplification, however, has a price: because it obscures the timing of loads, one cannot accurately calculate production costs on the basis of generating-unit details, such as minimum and maximum loading points, startup times and costs, and minimum shutdown times. To partially remedy these problems, ORCED analyzes production costs using the two load-duration curves, one for the three-month summer peak period and the other for the nine-month off-peak period. ORCED also simulates the effects of startup costs for those units with capacity factors of less than 10%.

For each season, the model has available to it 26 generating units. The first 25 units are characterized in terms of capacity, forced and planned outage rates, fuel type, heat rate, variable O&M costs, fixed O&M costs, and annual capital costs (based on initial construction cost, year of completion, and capitalization structure). The 26th unit is an energy-limited hydro unit, for which the inputs include, in addition to those noted above, the plant's capacity factor (equivalent to its maximum energy output for the year). This treatment of hydro as energy-limited ensures that hydro displaces the most expensive energy (i.e., at the top of the load-duration curves).

Figure 6.1 Example Load-Duration Curves for Peak and Off-Peak Seasons



The model dispatches these 26 generating units separately for the two seasons. Although the calculation process is the same for the two seasons, the results differ because of differences in the load-duration curves and because all the planned maintenance is assumed to occur in the off-peak season.

The plants are first dispatched against the load-duration curve on the basis of bid price, the default for which is variable (fuel plus variable O&M) costs. (If the user bids a zero price for a unit, the generator is treated as a must-run unit and is dispatched first by the model.) Because plants are not available 100% of the time, we also model forced outages on a probabilistic basis.[3] Thus, the higher-cost plants will see demands not only from customers, but "equivalent demands" based on the probability that plants lower in the dispatch order (i.e., less expensive) will be undergoing a forced outage. The model creates an equivalent load-duration curve for each plant, which extends the amount of time the plant runs based on the forced-outage rates of the plants lower in the dispatch order.

Model results include spot prices for each point on the two load-duration curves. These prices are based on the bid prices for each generator. The prices also reflect any externally imposed uplift charge, capacity charge, or emissions taxes. Finally, the prices during high-demand hours reflect generating-unit startup costs and the costs of unserved energy for those hours that unconstrained demand exceeds supply. See Appendix F for more details on the inputs and results from ORCED.

ORCED can be run iteratively to estimate the response of customers to changes in overall and time-of-use electricity prices. User inputs include an overall price elasticity of demand and a time-of-use elasticity. The overall price elasticity adjusts the entire load-duration curve up or down in response to decreases or increases in the average price of electricity. The time-of-use elasticity adjusts each point on the load-duration curve up or down based on price decreases or increases during that time period.

In addition, the model can use the time-of-use elasticity to compute the value of unserved energy (in ¢/kWh) that equilibrates supply and demand when unconstrained demand would otherwise exceed online supply. Alternatively, the user can input an estimate of the value of unserved energy, which is then used to calculate the costs associated with those times when unconstrained demand would exceed supply. A third approach involves user specification of a minimum reserve margin and associated annual capacity payment (in $/kW-year) to pay for this "extra" capacity.

In addition to dispatching power plants and computing production costs, the model can also "optimize" the mix of generating units available for the year of analysis. (That is, the model includes a capacity-expansion module as well as a production-costing module.) We put optimize in quotes because the factor on which to optimize is almost certain to be different for a competitive electricity industry than it was for the regulated electric utility industry. For example, the model could choose from among the following optimization functions:

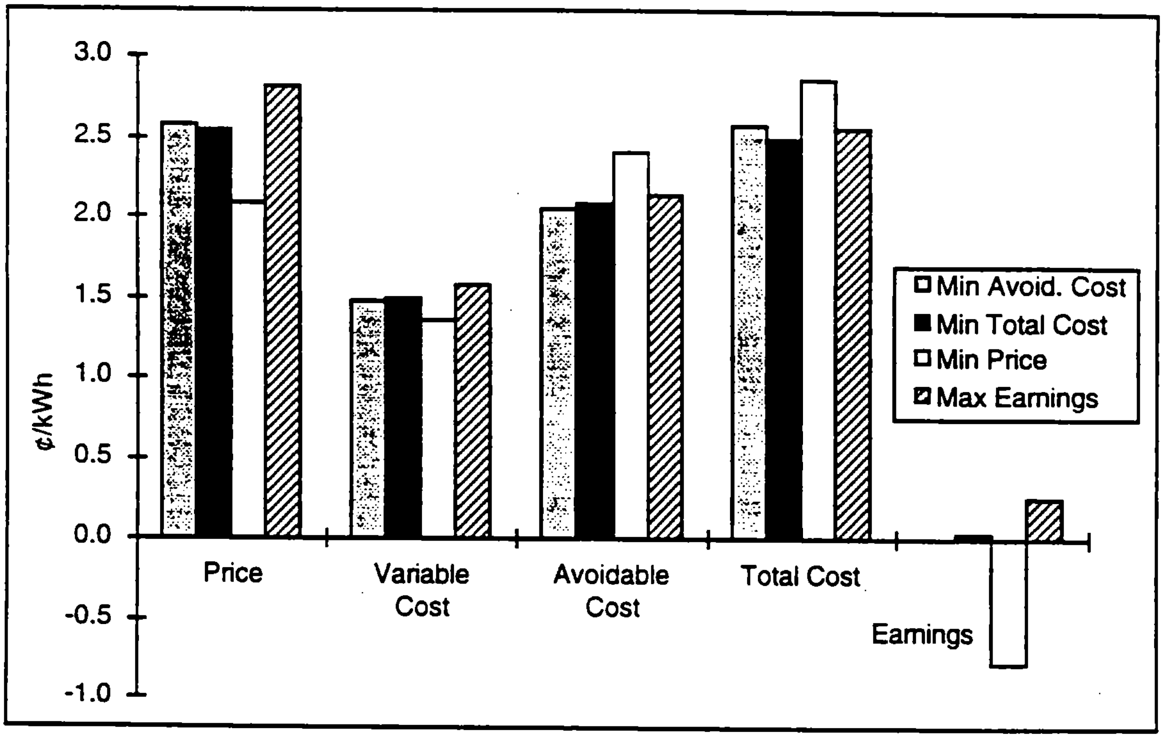
- Minimize total costs;
- Minimize avoidable costs (fuel, variable and fixed O&M);
- Minimize electricity prices; or
- Maximize generator earnings.

In Figure 6.2 we show the impact of different objective functions for optimization. Minimizing price does not necessarily minimize cost, because prices are based on the variable costs only and ignore fixed costs. Given choices of technology, ORCED would select low variable cost but high total cost technologies. Conversely, maximizing earnings does not raise total cost. Instead, the model selects high variable/low fixed cost technologies. For our analysis we chose to optimize on minimizing avoidable costs; we made this choice because it was conceptually the most appealing and the results were the most reasonable for a system-wide optimization. For plants not yet built, their capital costs as well as all operating costs are avoidable. Since no costs have been expended to build them, their construction costs are not "sunk" and can be avoided by not building them.

In addition to specifying the optimization function, the user can also specify constraints on individual generating units or the mix as a whole. For example, the user could set minimum and/or maximum capacity levels for each generator. Maximum levels could be specified for those units that were built earlier. Minimum levels could be specified for those units that must be available for policy reasons (e.g., renewable resources that might not be fully cost-effective but are deemed desirable from a broad societal perspective). Also, minimum levels for new plants may be specified to represent plants built between the current year and the study year. Otherwise, the model may choose not to build these intermediate plants, selecting only those with the most advanced technologies. Constraints could be specified for a minimum capacity reserve margin, for a maximum carbon emission allowance, or to ensure that each generating unit recovers at least its variable plus avoidable fixed costs, and so on.

Since ORCED is written in Microsoft Excel, there are several methods that can be used for optimization. The easiest is to use the built-in Solver tool. A single cell can be identified as the objective function to be minimized, and other cells can be identified as variables, with constraints placed on their values and/or other parameters within the spreadsheet. Since the problem is non-linear, Solver uses a Generalized Reduced Gradient method, running the model thousands of times searching for a solution. Another method, which is generally slower but avoids problems of local optima, is the use of genetic algorithms.

Figure 6.2 Generation Price and Costs Using Different Optimizations (10% Fixed Reserve Margin)



6.4 SCENARIOS FOR 2010

6.4.1 Calibration to EIA AEO97

Before analyzing the two end-use efficiency scenarios, we first calibrated ORCED results to those produced by EIA's NEMS model for 1995 and 2010. Unfortunately, reconciling the two sets of results to each other is difficult because of differences in the ways that the two modeling systems classify various costs (e.g., fuel, variable O&M, fixed O&M, and capital costs associated with generation) as well as EIA's inclusion of administrative and general (A&G) and customer service costs in the basic categories of generation, transmission, and distribution costs.[4] Because of these difficulties, our numbers do not always match the EIA numbers exactly.

This calibration ensures that the assumptions concerning the mix of generating units, fuel prices, customer demand, environmental regulations, and so on are consistent between ORCED and those developed by EIA. For example, both sets of results assume the continuation of current economic and environmental policies affecting the U.S. electricity industry. However, EPA's proposed regulations to tighten standards for emissions of nitrogen oxides and small particulate matter are reflected in neither the EIA nor the ORCED results.

We first developed a base case for the year 2010 that includes the same mix of generating units (in both capacity and energy) as that produced by EIA, with the same reserve margin (11%), as shown in Table 6.1. In addition to data from the AEO97, we used other data from EIA (EIA 1996b, EIA 1996c, EIA 1995), as well as data from the North American Electric Reliability Council (NERC 1996), the Electric Power Research Institute (EPRI 1993), and a compilation of various official databases by Resource Data International, Inc. (RDI 1996).

Table 6.1 Comparison of Year 2010 AEO97 and ORCED Estimates of U.S. Generating Capacity and Generation

	Percent of generating capacity		Percent of generation	
	EIA	ORCED	EIA	ORCED
Hydro+other renewables	13.4	11.3	9.6	9.2
Coal	35.0	36.9	50.1	50.8
Nuclear	10.2	11.1	15.8	15.5
Oil	3.2	3.1	1.5	0.1
Gas	38.3	37.6	23.0	24.4

ORCED analyzes the generation sector only; the model is silent with respect to the costs of transmission, distribution, and customer service. ORCED produces the following cost estimates for 2010, all expressed in 1995 dollars and adjusted upward by 1/0.93 to reflect the 7% T&D losses between the generator busbar and the customer meter:[5]

Fuel	1.35
Variable O&M	0.18
Fixed O&M	0.51
Capital	1.00
Total	3.04¢/kWh

We developed an estimate of the EIA capital cost of generation by subtracting estimates of the capital costs associated with transmission, distribution, and administrative and general (A&G) services from EIA's total capital cost:

[2.32 - (0.52 + 1.46) * 0.63 - 0.08] = 1.00¢/kWh.[6]
Total (Trans + Dist) A&G

Our estimate of the EIA fuel cost is based on the sum of EIA's fuel cost plus 88% of its wholesale purchase cost:

(0.98 + 0.67*0.88) = 1.57¢/kWh.[7]
Fuel Wholesale

We used the ORCED estimates of fixed and variable O&M costs to impute a comparable (i.e., equal) value for EIA.

The net result is very close agreement between the ORCED and EIA scenarios for 2010 (Table 6.2). EIA's estimate of the total cost of generation (3.26¢/kWh) is 7% higher than the ORCED result (3.04¢/kWh). The ORCED cost is lower because ORCED dispatches fewer expensive oil-fired resources than does the EIA model (Table 6.1). These differences in dispatch and variable costs occur because ORCED dispatches generation nationwide and ignores transmission constraints. The close agreement between EIA and ORCED results, in spite of all the adjustments required to produce a set of internally consistent and comparably defined terms, is reassuring. It lends confidence to our development of alternative cases in which we intended to reflect more fully than EIA did the effects of competition in bulk-power markets.

Table 6.2 Comparison of EIA and ORCED Estimates of Generation Costs (1995¢/kWh)

Generation costs	EIA AEO97	ORCED
Capital	1.00	0.99
Fuel	1.57	1.36
O&M	0.69	0.69
Total	3.26	3.04

6.4.2 The Base Case for a Competitive Market

Beginning with the AEO97 case, we developed a case intended to reflect the workings of a fully competitive bulk-power market in the year 2010. (The AEO assumes a continuation of current economic regulation, as indicated above, and therefore does not account for the possible effects of a restructured and largely competitive U.S. electricity industry.) To reflect these changes, we let the model select the amounts of each of the generating units that minimize the sum of variable plus avoidable costs. Instead of specifying the amount of generating capacity that must be online in 2010 (to yield a 10.7% reserve margin in the AEO97 case), we allowed the model to select the amount of capacity that minimized the cost of the power-supply system plus the cost of unserved energy. We used a demand elasticity of -0.05 for those time periods when capacity is insufficient to meet unconstrained demand. The resultant optimization yielded a reserve margin of 6.8%.

In general, we set prices equal to their real-time (hourly) values based on the variable (fuel plus variable O&M) cost of the unit on the margin each hour of the year, adjusted overall electricity demand to reflect lower prices using an assumed overall elasticity of -0.5, and adjusted the load shape to reflect the response to real-time pricing using a value of -0.1 for the price elasticity within each time period.

Beginning with the ORCED run that matches the AEO97 values for 2010, we first reran the model allowing it to select the "optimal" amounts of generating capacity from among all the plants that, according to EIA, are scheduled to come online after the year 1998. (The optimization was based on a minimization of avoidable costs.) We also allowed the model to select plants for retirement. For each of the new plants, we use the levelized fixed charges rate to calculate the annual capital cost of the plant and treat all fixed costs (both capital and O&M) as avoidable.

Next, we adjusted the load-duration curves for the two seasons simulated by the model (peak and off-peak). The new system load has a peak demand that is 3.4% below the AEO97 case and a total demand that is 1.2% higher. We then reran ORCED using the new load shapes. Table 6.3 compares the two sets of results. Although demand is higher in the restructuring case than in the AEO97 base case, carbon emissions are lower. The lower carbon emissions are the result of reduced coal use and increased natural gas use in the restructuring case.

Notice that, under restructuring, the total generating cost goes down 0.3¢/kWh and yet the system average price increases slightly. In a deregulated market, prices will be based on the variable cost (or bid price) of the most expensive plant at that time. This is known as the "market clearing price." Consequently, the link between total costs and prices is broken. Whereas current electric utility regulation sets prices to recover total costs, future prices may, or may not, be sufficient to recover all costs.

Overall, ORCED prices under restructuring did not differ greatly from the AEO97 price forecast. Part of the reason for this similarity of results is that EIA did assume some cost decreases in their model; we did not assume further O&M cost decreases on a plant-by-plant basis due to the pressure of competition. Also, the objective function used in our cases was to minimize avoidable costs on a system-wide basis. This did not necessarily create the lowest-priced scenario, as discussed in section 6.3. Because prices were similar to those in the AEO97 (less than 5% difference when factoring in transmission and distribution prices), we simply used the AEO97 price forecasts for analysis of energy-efficiency savings in the other chapters of this report.

Table 6.3 Comparison of Year 2010-Forecasts: AEO97 and the ORCED Base Case for a Competitive Electricity Industry

	AEO97	Competitive Industry Restructuring
Peak demand, GW	734	709
Total end-use electricity sales, TWh	3,784	3,828
System load factor, %	62.8	65.7
Reserve margin, %	10.7	6.8
Generation shares, %		
Coal	50.8	47.4
Gas	24.4	29.2
Other	24.8	23.4
Generation prices and costs, ¢/kWh		
Retail price	3.04	3.02
Variable cost	1.43	1.45
Total cost	2.81	2.51
Carbon emissions, MtC	631	625

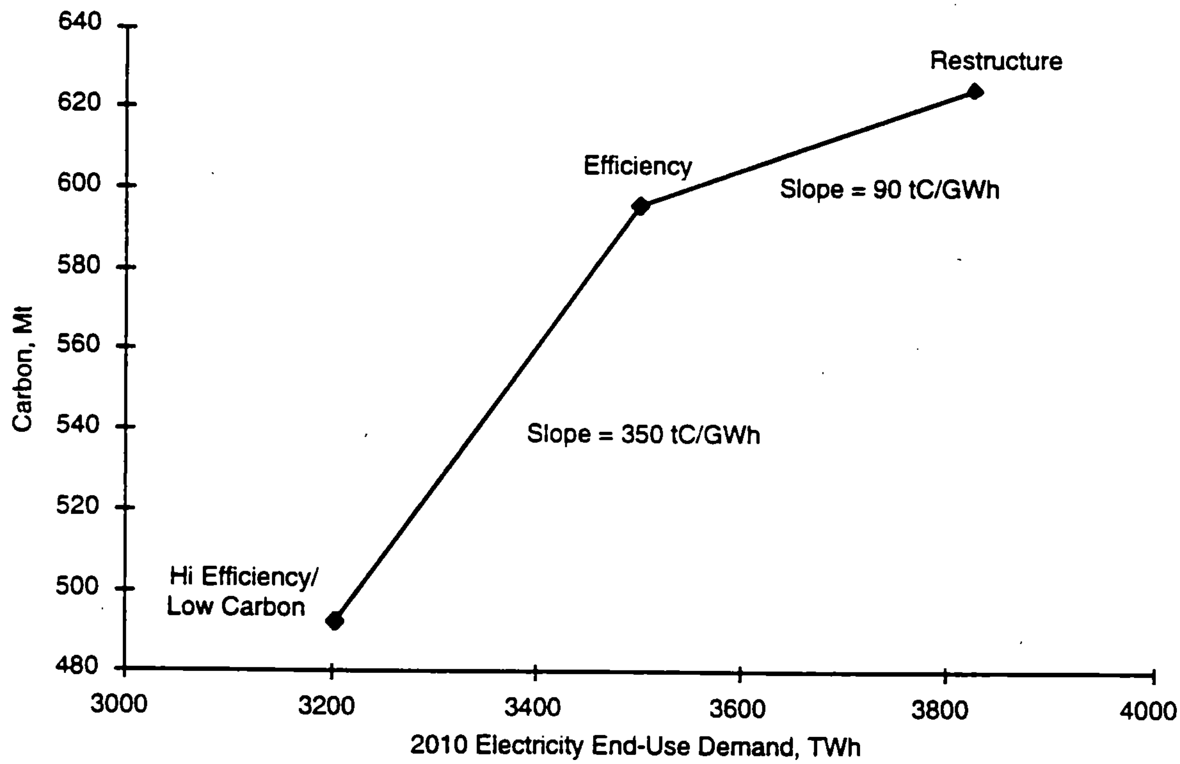
6.4.3 Efficiency and High-Efficiency/Low-Carbon Cases

We next applied the electricity-savings estimates, described in Chapter 3 for the residential and commercial sectors and in Chapter 4 for the industrial sector, to adjust the aggregate load shape for the United States as a whole. We then reran ORCED using the new, lower load shapes. As in the reference case, capacity was optimized to minimize avoided costs, and dispatched on the basis of lowest variable costs. Avoided costs for existing plants only included their variable, start-up, and fixed O&M costs, while plants to be built between 1997 and 2010 also included the annualized capital cost of their construction. As part of the high-efficiency/low-carbon case, we included an additional cost of $50 per tonne of carbon, to be consistent with the rationale used in the demand-side efficiency scenarios.

Once power plant production levels were determined, carbon production and primary energy use could be calculated. We calculated marginal carbon savings, the carbon saved by the reduction in energy, by taking the difference in carbon production and dividing by the reduction in energy demand. This is in contrast to using the average carbon intensity as an approximation of the carbon saved per unit of energy saved. The marginal carbon and energy savings take into account the change in production mix that occurs with energy- efficiency and carbon-reduction measures. A plot of the carbon savings and primary energy used in each scenario shows the changes as a function of the end-use energy saved (Figures 6.3 and 6.4). The slopes of the lines represent the marginal carbon and primary energy saved.

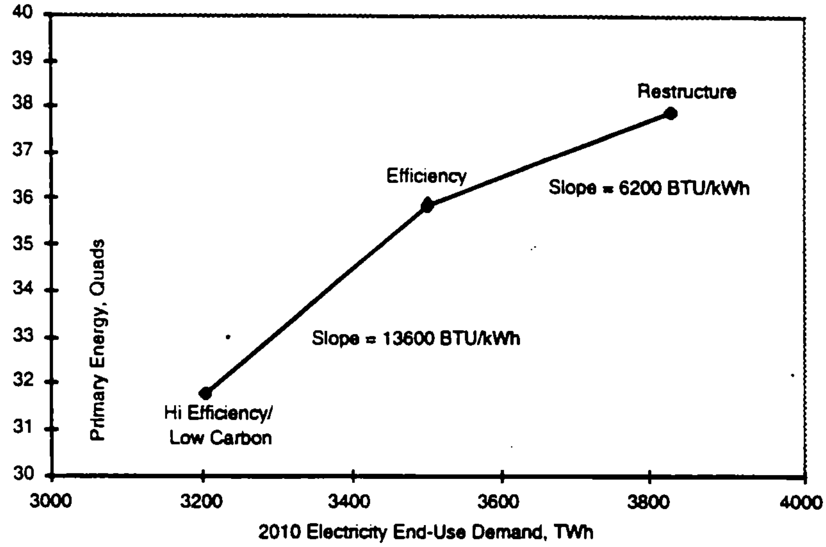
Table 6.4 summarizes the results for the three scenarios. Table 6.5 describes these results in terms of percent change relative to the base case for a competitive utility industry. The efficiency case yielded a 8.5% reduction in electricity end-use energy and the high-efficiency/low-carbon case reduced end-use energy by 16.3% relative to the restructuring case summarized in Table 6.3.

Figure 6.3 Carbon Production Versus End-Use Demand: Reductions Due to Energy Efficiency and Carbon Management



Note: Slope is equal to marginal carbon savings in tonnes of carbon per gigawatt-hour.

Figure 6.4 Primary Energy Production Versus End-Use Demand: Reductions Due to Energy Efficiency and Carbon Management



Note: Slope is equal to marginal energy savings in Btu per kilowatt-hour.

Table 6.4 Comparison of Year 2010 Forecasts: Results of Efficiency and High-Efficiency/Low-Carbon Scenarios

	Competitive Industry Optimization	Efficiency	High-Efficiency/ Low-Carbon
Peak demand, GW	709	651	596
Total Primary Energy used, quads	37.9	35.9	31.8
Total electricity generated, TWh	4,090	3,740	3,420
Total end-use electricity demand, TWh	3,830	3,500	3,200
System load factor, %	65.7	65.5	65.5
Reserve margin, %	6.8	7.9	12.9
Generation shares, %			
Coal	47.4	52.1	46.2
Gas	29.2	22.2	26.0
Other	23.4	25.7	27.8
Generation prices and costs, ¢/kWh			
Retail price	3.02	3.03	3.66
Variable cost	1.45	1.43	2.07
Total cost	2.51	2.46	3.21
Carbon emissions, MtC	625	596	492
Average carbon emissions, kg/MWh	163	170	154
Marginal carbon saved, kg/MWh	-	89	350

Table 6.5 Comparison of Year 2010 Forecasts: Effects of Efficiency and High-Efficiency/Low-Carbon Scenarios

	Change relative to the competitive utility industry base case	
	Efficiency	High Efficiency/Low Carbon
Peak demand	-8.2%	-16.0%
Total energy	-8.5%	-16.3%
System load factor	-0.2% points	-0.2% points
Reserve margin	+1.1% points	+6.1% points
Generation shares		
Coal	+4.7% points	-1.2% points
Gas	-7.0% points	-3.2% points
Other	+2.3% points	+4.4% points
Generation prices and costs		
Retail price	+1%	+21%
Variable cost	-1%	+43%
Total cost	-2%	+28%
Carbon emissions	-4.6%	-21.2%

The efficiency scenario forecasts a lower percentage reduction in carbon (4.6%) than in end-use energy (8.5%) (Figure 6.5). The difference occurs because lower end-use demands translate into less construction and operation of high-efficiency gas-fired combustion turbines and combined-cycle units (Figure 6.6). (Because of their high capital costs, ORCED selects only the minimum amounts of advanced coal and renewable technologies in the base restructuring case.) In the efficiency case, relative to the restructuring case, capacity and generation for combined-cycle units declines by about 27%; capacity for combustion turbines drops 28% (generation drops by 68%); and coal and gas-powered steam plants actually increase their production slightly.

Identification of high-efficiency gas-fired combustion turbines and combined-cycle units as the marginal plants under consideration has the effect of substantially lowering the avoided carbon from electric efficiency improvements. The forecasts contained in AEO97 are consistent with this assumption through the year 2010. For example, page 49 of the AEO97 states that, "of the new capacity [required through 2015], 81 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas."

In contrast, the HE/LC case forecasts a higher percentage reduction in carbon (21.2%) than in end-use energy (16.3%). This is because the inclusion of the charge of $50 per tonne of carbon changes the mix of technologies used to produce electricity so that low-carbon supply options are favored. Over 16% of the coal capacity is retired in this scenario, and the remaining, more-efficient coal plants operate at a lower capacity factor. Overall, generation from coal declines 18% compared to the reference case. Capacity from combined cycle plants actually increases over the amount in the efficiency case, but still has a 14% decline from the reference case. Combustion turbine generation declines 84% from the reference case while combined cycle generation declines only 13%.

Figure 6.5 Energy and Carbon Changes from Restructure Case

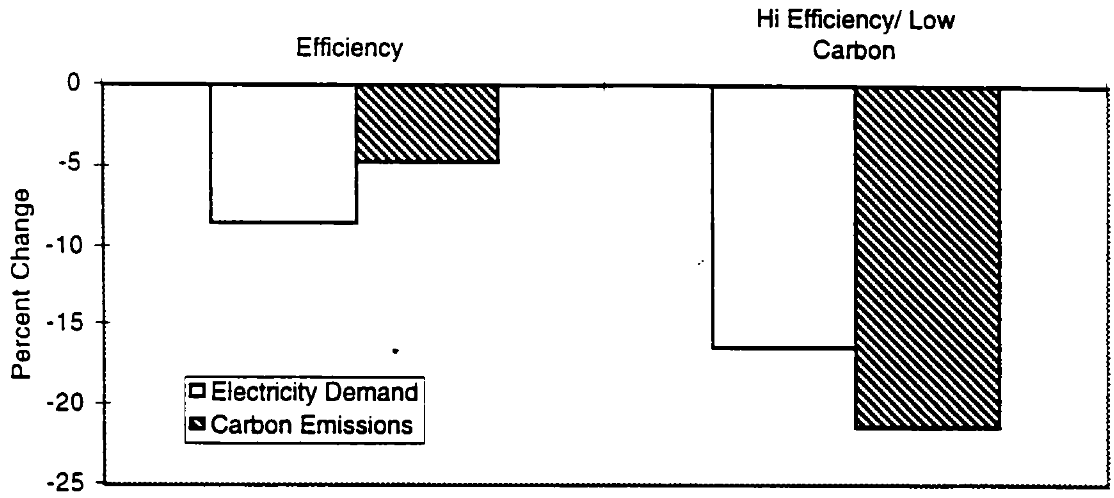
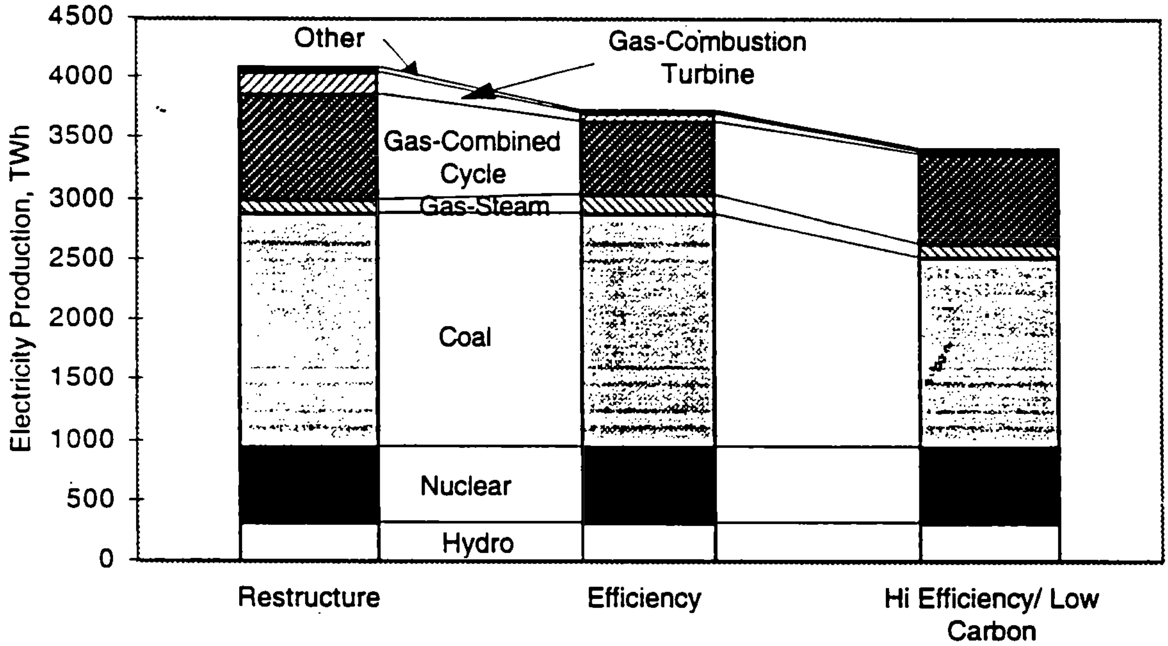


Figure 6.6 Generation by Technology Under Each Scenario



Compared to the reference case, generating prices and costs remain about the same under the efficiency scenario. In the HE/LC scenario, prices and costs increase about two-thirds of a cent because of the additional charge of $50/tonne of carbon. This carbon charge represents a 1.4¢/kWh increase to the more expensive coal plants, but only a 0.5¢/kWh increase to the better gas-fired combined cycle plants. ORCED redispatched and changed capacities so that the cost increase would be minimized. Note that, although the generation price increases by 21%, the price of generation represents only about half of the total price of electricity. Keeping transmission, distribution, and customer service prices the same, the total price increase would be only 10%.

Because electricity prices are essentially unchanged under the efficiency scenario (changing from only 6.20¢/kWh to 6.22¢/kWh including other components), total electricity costs to consumers decrease by an amount that is proportionate to the reduced electricity demand (i.e., 330 TWh). Thus, the cost reduction is approximately $20 billion. This value takes into account the savings in transmission, distribution, and customer service costs included in the full retail price of electricity. The high-efficiency/low-carbon case yields slightly lower savings of around $18 billion. Total energy savings almost double to 630 TWh, but the price increase of 0.65¢/kWh due to the carbon charge cuts into the overall savings.

One way to measure the cost impact of the $50/tonne of carbon cost is to evaluate the extra cost due to plant operation changes (redispatch, retirements, and new construction). In the high-efficiency/low-carbon case, we construct and operate the plants as optimized with the carbon charge. If we remove the charge, but construct and dispatch plants as in the high-efficiency/low-carbon case, we are no longer operating at minimum cost. The excess above the minimum cost is about $2.2 billion. Dividing this amount by the tons of carbon saved from the minimum-cost case yields an average cost of $30 per tonne of carbon saved.

Allocating the carbon savings in the efficiency case between the buildings and industrial sectors, we find that the buildings sector (residential and commercial) saved 19.4 Mt of carbon while the industrial sector saved 9.6 Mt (Table 6.6). The carbon savings for each were proportional to their savings in electricity, since electric generation is determined by the system load.

Table 6.6 Carbon Reductions from Electricity Savings by Sector under the Efficiency and High-Efficiency/Low-Carbon Cases (MtC)

Sector	Efficiency Case	High-Efficiency/Low-Carbon Case
Buildings (Residential)	10.9	49.2
Buildings (Commercial)	8.5	38.3
Industry	9.6	45.0
Total	29.0	132.5

Note: Transport is not included since electricity use in that sector is negligible.

Some of the 133 Mt of carbon that is forecast to be displaced by the high-efficiency/low-carbon case can be attributed to the end-use efficiency improvements in the buildings and industrial sectors. The remaining savings are attributed to the change in electricity generation mix that resulted from the charge of $50/tonne of carbon. Two methods of allocating the carbon savings between the end-use and supply sectors were examined.

- In the first method, ORCED modeled the high-efficiency/low-carbon case without the $50/tonne charge in the supply sector. The result was a savings of 56 MtC, attributed to energy efficiency alone. The rest of the carbon savings (77 MtC) is then attributed to the electricity sector.

- In the second method, ORCED modeled the restructure case with the $50/tonne charge in the supply sector, but without the demand reduction due to efficiency improvements. The result was a savings of 33 MtC, which is attributed to the electricity sector. The rest of the carbon savings (100 MtC) is attributed to the end-use sectors based on their energy savings.

The results of these alternative allocations (including the distribution of carbon savings across the buildings and industrial sectors) are shown in Table 6.7 and Figure 6.7. The total carbon that is displaced by the lower electricity demand is the same (133 MtC), but the allocation between the end-use and supply sectors varies widely depending on the method used to allocate the savings.

Because the savings involve a synergy between increased energy efficiency and changes to supply dispatching, it is difficult to identify the appropriate allocation of savings for the end-use vs. electricity supply sectors. To simplify matters, we used the average between the two methods described above. Specifically, the following averaging was used:

- The minimum carbon reduction attributed to electricity end-use efficiencies is 56 MtC (Method 1) and the maximum is 100 MtC (Method 2). The average of 78 MtC is therefore assumed for the end-use sector.

- The minimum carbon reduction attributed to the electricity sector is 33 MtC (Method 2) and the maximum is 77 MtC (Method 1). The average of 55 MtC is therefore assumed for the electricity supply sector.

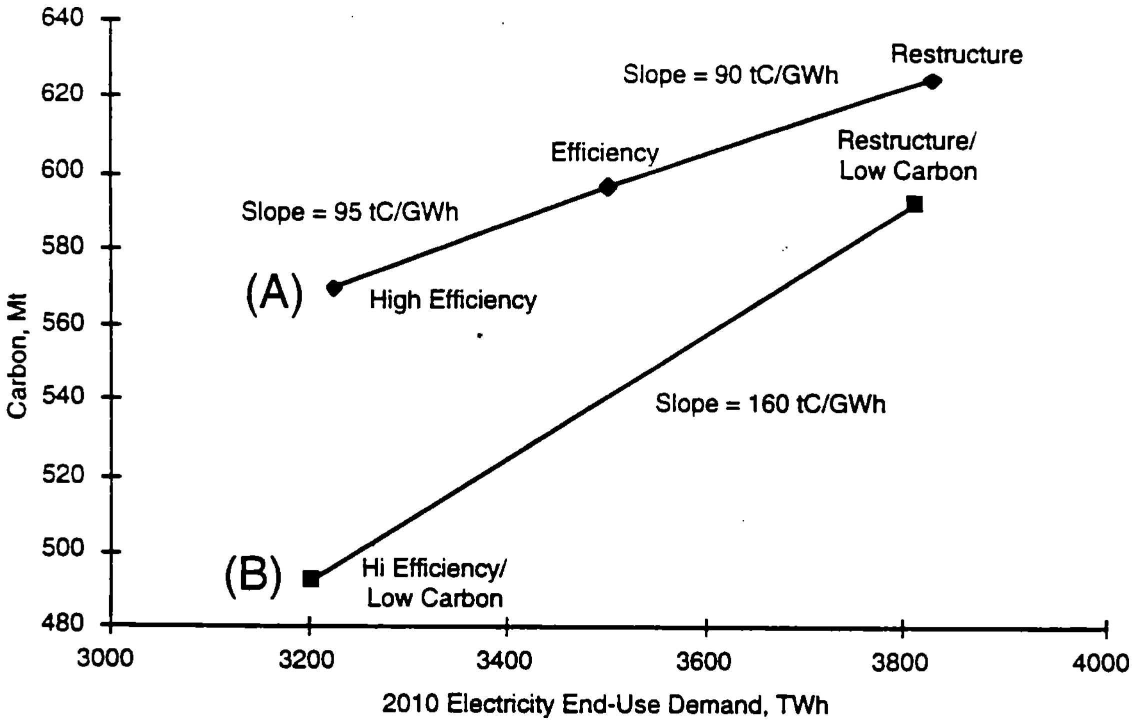
Table 6.7 summarizes this allocation process.

Table 6.7 Allocation of Carbon Reductions from the Electricity Saved by the High-Efficiency/Low-Carbon Case (MtC)

Sector	Method 1: Carbon Reduced by Energy Efficiency First	Method 2: Carbon Reduced by $50/tC Charge First	Final Allocation by Averaging
Buildings (Residential)	21	37	29
Buildings (Commercial)	16	29	22
Industry	19	34	27
Subtotal	56	100	78
Electricity Sector	77	33	55
Total	133	133	133

Based on the results shown in Figure 6.7, 160 tonnes of carbon are displaced for each GWh of electricity saved in the high-efficiency/low-carbon case with carbon permit price of $50/tonne, reflecting the introduction of new low-carbon technologies. This is the marginal carbon-to-energy ratio that is therefore used for analyzing the impacts of other carbon management strategies in the electricity sector in Chapter 7. This value is significantly higher than the marginal carbon-to-energy ratio used in the efficiency case (90 tonnes of carbon per GWh of electricity, as also shown in Figure 6.3), for the reasons noted earlier.

Figure 6.7 Carbon Reductions Due to Energy Efficiency and Carbon Management: (A) Without a Carbon Charge and (B) With a Carbon Charge of $50/Tonne



Note: Slope is equal to marginal carbon savings in tonnes of carbon per gigawatt-hour. In (A), the high-efficiency option represents all the assumptions of the high-efficiency/low-carbon scenario except that there is no charge for carbon.

6.5 SUMMARY

The U.S. electricity industry is undergoing massive change. Because the process is far from complete, it is even more difficult to make estimates about electricity production and use for the year 2010 than it would otherwise be. However, we developed a reasonable and internally consistent picture of electricity demand and supply for the year 2010 on the basis of EIA's AEO97 projection and additional simulations with the Oak Ridge Competitive Electricity Dispatch (ORCED) model.

ORCED was used to simulate the operation of the U.S. electric power supply system in 2010. We first calibrated our input data so that our results closely matched those produced by EIA for its *Annual Energy Outlook 1997.* We then developed a case for 2010 that is intended to reflect the ways in which a fully competitive industry might operate. Compared to the AEO97, these results suggest greater electricity use, lower peak demand, and a generation mix that includes more natural gas and less coal. Thus, although consumption is higher, carbon emissions are lower.

We then simulated the operation of this competitive electricity industry given the efficiency-induced reductions in electricity use in the residential, commercial, and industrial sectors as described in Chapters 3 and 4. The efficiency case reduced electricity demand by 9%, which led to a 5% reduction in carbon emissions. The high-efficiency/low-carbon case reduced electricity use by 16%, which led to a 21% reduction in carbon emissions.

6.6 REFERENCES

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ENDNOTES

[1] States will continue to oversee power-plant siting and environmental emissions.

[2] The value of unserved energy is the price that customers would be willing to pay for electricity that is unavailable as a result of demand exceeding supply.

[3] The amount of computer time required for a full simulation depends strongly on the number of generators treated probabilistically. We found a reasonable tradeoff between computing time and accuracy when about 10 plants are modeled probabilistically and the other 16 are derated.

[4] Inclusion or exclusion of the data for cogenerators (which account for about 4% of electricity in the year 2010) is another source of confusion.

[5] According to AEO97, total generation in 1995 was 3246 billion kWh and sales totaled 3008 billion kWh, implying a loss of 7.3%.

[6] The 63% multiplier for T&D represents the percentage of T&D costs attributable to capital as opposed to O&M.

[7] This 88% multiplier is derived from ORCED's estimates of fuel and O&M costs of 1.35¢/kWh for fuel and 0.18 ¢/kWh for O&M. The 88% then is [=1.35/(1.35+0.18)].

Chapter 7

ELECTRICITY SUPPLY TECHNOLOGIES

7.1 INTRODUCTION

The electricity industry has many supply-side options at its disposal to reduce or offset carbon dioxide emissions from electricity production by the year 2010. One of these options, reconfiguring the generation mix to reflect a $50/tonne charge for carbon, was discussed in Chapter 6. We labeled this option "carbon-ordered dispatching" because it involves the same technologies that were considered in the AEO97 reference case. Electricity was redispatched from the existing generation mix, and the construction and retirement of power plants also changed, but no new technologies were introduced. Chapter 7 considers other electricity supply technology options, including:

- Repowering coal-based power plants with natural gas;
- Implementing renewable electricity technologies;
- Improving efficiency in generation and transmission and distribution (T&D) systems;
- Extending the life of existing nuclear plants; and
- Constructing new power plants using advanced coal technologies.

Each of these options is assessed independently. Because interactions among the options are not taken into account, there is a likely possibility of double-counting with respect to the actual emissions reduction potential.

The viability and costs of these supply options in 2010 are based on the assumption that the electricity grid is transformed by the carbon-ordered dispatching that occurs under the "high-efficiency/low-carbon" (HE/LC) scenario, as described in Chapter 6. Thus, since we assume that considerable decarbonization has already taken place, this chapter addresses the question: What additional supply technology options now make sense in a scenario in which carbon has acquired a value of $50/tonne? We conclude by discussing the significant contribution that renewable energy technologies can make by the year 2020.

7.2 REPOWERING COAL-BASED POWER PLANTS WITH NATURAL GAS

The conversion of existing coal-fired power plants to operate on natural gas (via repowering) is one option to significantly increase the efficiency of power generation and reduce carbon emissions in the U.S. electric power sector.[1] Natural gas is a less carbon-intensive fuel and its use also reduces emissions of the following criteria air pollutants: sulfur dioxide (SO_2), nitrogen oxide (NO_x), total suspended particulates (TSP), and hazardous air pollutants (HAPs). Our analysis shows that natural gas combined cycle (NGCC) is a cost-effective power generation technology and carbon emission reduction option. Depending upon assumptions regarding the differential in the delivered price between natural gas and coal, the price of carbon permits, and environmental externality values for criteria air pollutants, we found that carbon emissions of up to 238 MtC could be reduced annually through repowering.

7.2.1 Repowering Approaches

The simplest repowering approach is *site repowering*, where the existing power plant site is reused with an entirely new NGCC system. Cost and performance data for the General Electric "H" frame turbine was used; this class of turbine will be the most efficient in the post-2000 period, with the lowest cost per kilowatt of capacity. While site repowering provides the highest cycle efficiency (since none of the existing boiler island equipment is reused), it also requires a greater capital investment (see Appendix G-1).

The more conventional approach is referred to as *steam turbine repowering*. In this case, a new gas turbine and heat recovery steam generator (HRSG) are integrated with the existing steam turbine and auxiliary equipment from the coal plant. Due to age of equipment and the fact that the steam turbine was designed for linkage with a coal-fired boiler, the efficiency of a *repowered* steam turbine plant would be lower than at a *site repowered* plant. The steam turbine repowering option has a higher operating cost (due to the lower efficiency) but a lower capital cost (see Appendix G-1).

The cost-effectiveness ($/tC) of both repowering options was examined for all coal-fired power plants greater than 50 megawatts (MW).[2] Included in the cost calculation were the cost of repowering, hook-up, and transmission. We analyzed the site repowering results for the two alternative gas/coal price differentials: $0.72 and $1.18 per million Btu (MBtu)[3], three price ranges for carbon permits (<$50/tonne, $50-100/tonne, and $101-150/tonne), and three environmental externality values for SO_2 and NO_x (none, low, and high). In addition, a sensitivity analysis was performed to examine the impact on cost-effectiveness if additional natural gas pipeline infrastructure (hook-up and transmission) were not needed to ensure gas deliverability to repowered plants. This sensitivity analysis (referred to as the "no additional transmission cost" case) was conducted only for those power plants that are currently connected to the natural gas pipeline network (i.e., dual-fuel). Appendix G-3 contains a complete description of the methodological steps and key data parameters.

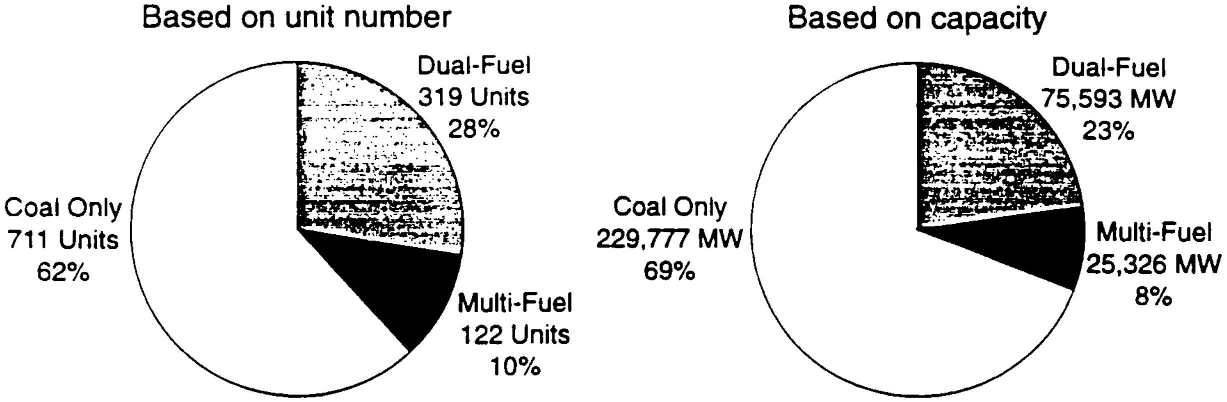
The analytical approach was static in that the cost of repowering was computed for each candidate power plant but the analysis did not optimize unit/plant production cost, dispatch, or system load. Moreover, for the steam repowering case, the largest steam turbine (not each individual steam turbine) at the plant was repowered to generate the equivalent of 1995 plant output (kilowatt-hours, kWh), since this is both more economic and consistent with industry practice than repowering each turbine. Lastly, the gas delivery infrastructure costs (hook-up and transmission) were derived assuming (1) no excess capacity in the current delivery system, and (2) that if such a fuel-switching strategy were implemented, the natural gas pipeline industry would build capacity (even if done incrementally) to meet the total estimated gas requirements of repowering all candidate plants and allocate appropriate delivery costs to each repowered plant. Assumptions regarding gas deliverability are described below in Section 7.2.2.2.

7.2.2 Repowering Issues

In 1995, there was 335 GW of coal-fired capacity at 404 power plants in the United States. Figure 7.1 indicates that this capacity was comprised of:

- 319 dual-fuel units (units that can burn both coal and natural gas),
- 122 multi-fuel units (coal-fired units at sites with natural gas or petroleum units), and
- 711 coal-fired units (units at coal-only plant sites).

Figure 7.1 Candidate Coal-Fired Power Plants for NGCC Repowering



These categories reflect differences in the investment cost of conversion and deliverability of natural gas (i.e., those plant sites consuming gas in 1995 would have a natural gas pipeline connection, thereby resulting in a lower hookup cost.)

7.2.2.1 Increase in Natural Gas Demand

Utility gas consumption in 1995 was 3.5 trillion cubic feet (TCF). Figures 7.2 and 7.3 show the increases in natural gas demand from this base that would result from either site or steam turbine repowering for each of three cost-effectiveness values: less than $50/tC, $50-100/tC, and greater than $150/tC. The increase in gas demand ranges from 1.0 TCF (<$50/tC) to 4.9 TCF ($50-100/tC) in the low gas/coal price differential case without externalities. This quantity of gas for repowered plants represents 29% and 140% increases in 1995 utility gas consumption, respectively.

If all the candidate coal-fired power plants were repowered with NGCC, natural gas demand in the utility sector would increase by 9.0 TCF/yr (site repowering) or 9.4 TCF/yr (steam turbine repowering) to either 12.5 TCF/yr or 12.9 TCF/yr, respectively, an increase of over 250% compared to current consumption levels.

The potential gas price increase resulting from NGCC repowered plants was not analyzed in this study. Only the current and projected gas/coal price differentials expected under AEO97 were included in the cost analysis. However, EIA has prepared a preliminary estimate; they found that an 11 TCF increase in demand would increase natural gas prices by $3.09/MBtu over 20 years (1995-2015), if coal-fired power plants were converted to natural gas when scheduled for life extension/refurbishment and there was considerable demand-side energy-efficiency investment.

Figure 7.2 Incremental Increase in Gas Consumption Resulting from Coal to Gas Conversion with Constant 1995 Gas/Coal Price Differential ($0.72/MBtu)

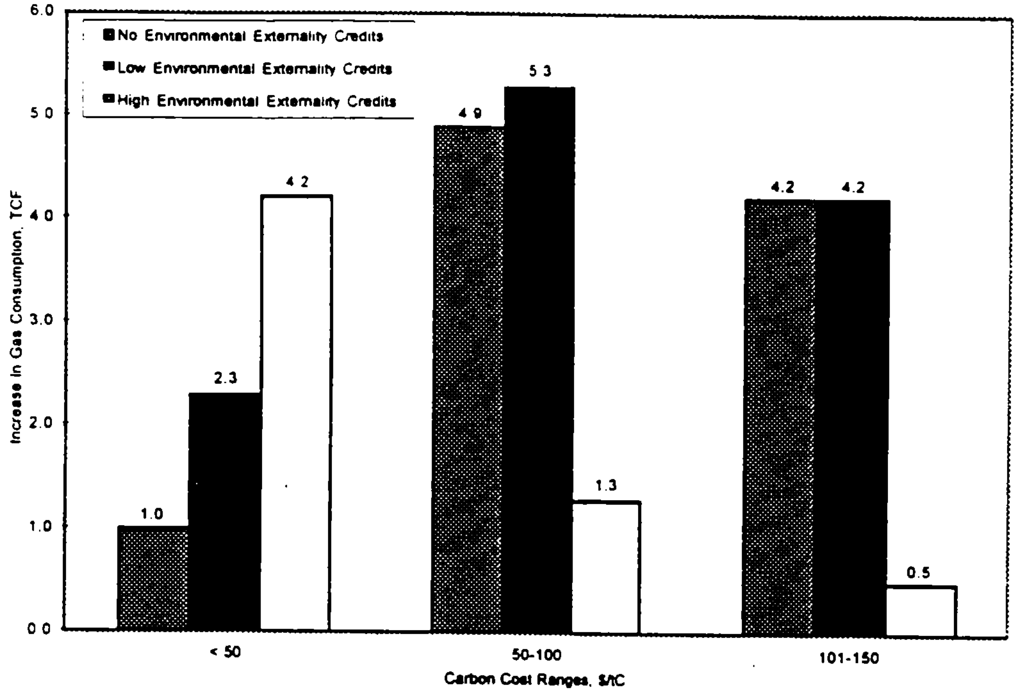
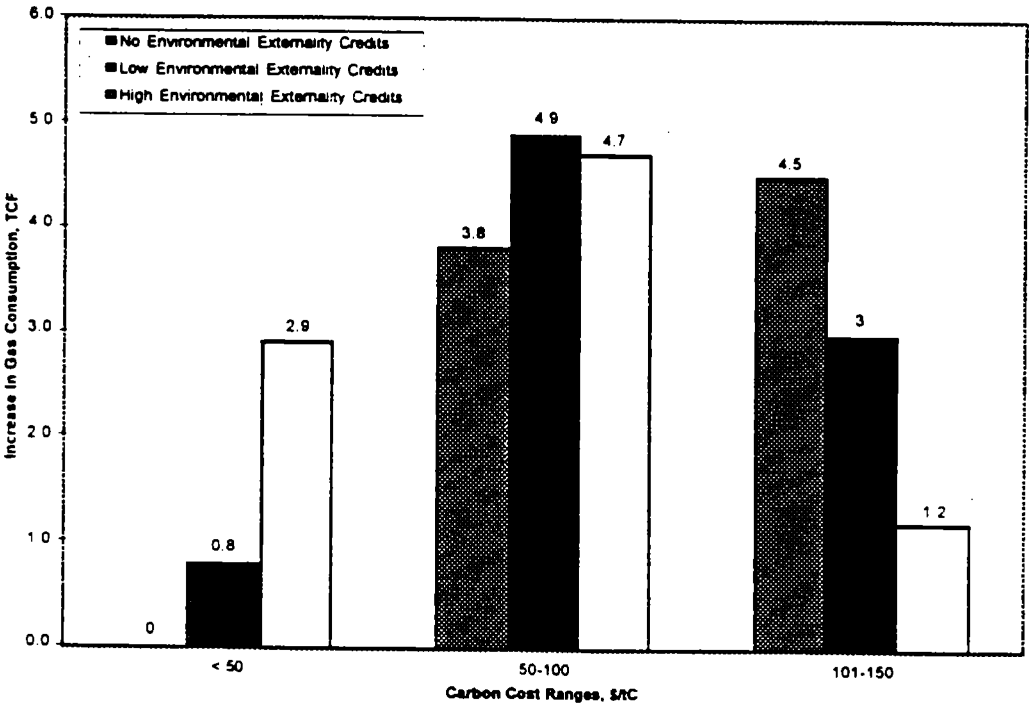


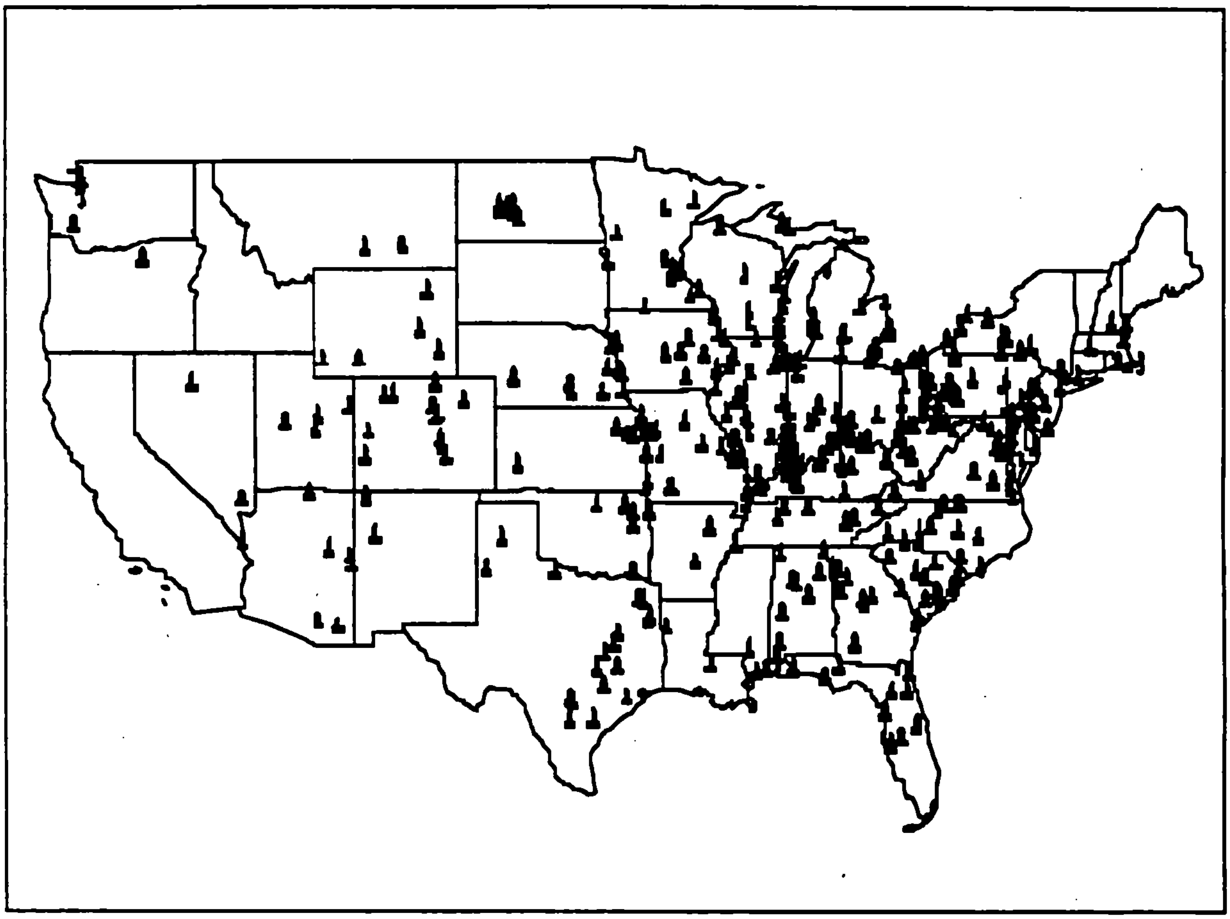
Figure 7.3 Incremental Increase in Gas Consumption Resulting from Coal to Gas Conversion with Constant 2010 Gas/Coal Price Differential ($1.18/MBtu)



7.2.2.2 Gas Deliverability

The spatial distribution of the initial 404 candidate plants is depicted in Figure 7.4. Some of the candidate plants were not considered for repowering since they were (1) not considered economic by EIA, or (2) determined to be unnecessary due to reductions in demand arising from end-use efficiency improvements.[2] Most of the plants are located in the Mid-Atlantic, South Atlantic, Midwest, and Plains regions. While these are also primary gas-consuming regions served by major trunk lines, many industry experts believe there is limited unused or underutilized capacity in the current 1.2 million mile pipeline system (transmission - 264,900 miles; distribution - 935,000 miles; field - 62,200 miles). Since this capacity is necessary to accommodate peak winter demand and non-utility growth, it is of little value to power plants considering conversion, since these power plants require firm pipeline commitments.

Figure 7.4 Location of Candidate Plants for Coal/Gas Repowering in the U.S.



Due to the potentially significant increase in utility gas demand that could result from repowering (either site or steam turbine) coal-fired power plants, and the uncertainties regarding when repowering would take place, new pipeline capacity sufficient to serve all candidate plants was developed to ensure deliverability. A detailed assessment was performed (using a geographical information system, GIS) to compute the distance of each candidate power plant to its nearest trunk line. Cost estimates were derived for the cost of upgrading the lines to meet the increased gas demands (see Appendix G-4).[4] Table 7.1 summarizes the distance of the candidate plants to their closest production zone.

The requirement to add new pipeline capacity could affect the attractiveness of repowering as a carbon mitigation strategy. During 1994 and 1995, 1,200 to 1,500 miles of new pipeline were added to the system. According to Federal Energy Regulatory Commission (FERC) filings of pipeline projects, there are a considerable number of new pipelines and pipeline expansions that have been proposed, some of which are still pending approval. While mileage is not included with each filing, in the regions of concern (Central, Midwest, Northeast, and Southeast), more than 8,200 miles of pipe is projected to be added; this level of expansion is greater than the 1994-95 rate of addition. However, it is not known how long it will take to complete these proposed pipelines. Consequently, an accurate assessment of the ability to increase the rate of pipeline expansion/construction could not be estimated as a part of this study.

Table 7.1 Plant Distance from Production Zone

Range	Dual-Fuel		Multi-Fuel		Coal Only		Total	
(Miles)	# Units	%	# Units	%	# Units	%	# Units	%
60 - 440	48	37	5	12	55	22	108	26
440 - 620	33	25	8	19	64	26	105	25
620 - 890	30	23	15	35	59	24	104	25
890-1,480	19	15	15	35	67	27	101	24
Total	130	100	43	100	245	100	418	100

7.2.3 Emissions Reductions

Based on our analysis, repowering of coal-fired power plants with NGCC is a cost-effective carbon reduction strategy. Tables 7.2-7.4 summarize the site repowering results for the two alternative gas/coal price differentials: \$0.72 and \$1.18 per million Btu (MBtu), three price ranges for carbon permits (<\$50/tonne, \$50-100/tonne, and \$101-150/tonne), and three environmental externality values for SO_2 and NO_x (none, low, and high). The price differential of \$0.72/MBtu represents the 1995 gas/coal price differential held constant, while \$1.18/MBtu is EIA's forecasted price differential for the year 2010.[5,6] In addition to the "no externalities" case, two alternative market values were used for SO_2 and NO_x: low externalities represent \$0 per ton of SO_2 and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO_2 and \$1400 per ton of NO_x.

As can be seen in Table 7.2, given a carbon permit price of less than \$50/tC and a gas/coal price differential of \$0.72/MBtu, 30 to 119 MtC could be removed via NGCC site repowering, depending upon externality assumptions. When the price differential increases to \$1.18/MBtu, 0 to 83 MtC could be removed from utility emissions. Consequently, we see that a increase of \$0.46/MBtu in the price differential decreases carbon reductions from NGCC repowering by approximately 30 MtC. Although the disaggregated data are not presented, most of the carbon reduction in the <\$50/tC range actually occurs in the \$25-50/tC range.

An ancillary benefit of switching from coal to gas and improving conversion efficiency is reduction in SO_2 and NO_x,two criteria pollutants. At the <\$50/tC level, approximately 50% of the SO_2 and NO_x would be removed (depending on the externality value); at \$50-100/tC and higher almost all the remaining coal-fired SO_2 and NO_x emissions would be eliminated. If all the candidate plants were repowered, almost all of the SO_2 and most of the NO_x would be removed.

The economic value of the SO_2 and NO_x emissions reductions that would result from repowering of the plants was also assessed in this study. Using the methodology described in Appendix G-2, SO_2

was valued from \$0-100/ton; NO_x was valued at from \$700-1400/ton. These values were used as the basis for the environmental externality credits to offset the investment cost of repowering.

Table 7.2 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of <\$50/tonne

Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO_2 Removed (Mt)	Incremental NO_x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
	Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)				
None	30.3	0.5	0.7	26.8	1.0
Low	66.0	1.2	1.4	63.3	2.3
High	118.6	4.0	2.6	122.6	4.2
	Gas/Coal Price Differential in 2010 (\$1.18/MBtu)				
None	0	0	0	0	0
Low	23.6	0.3	0.6	20.2	0.8
High	83.4	2.5	1.9	83.3	2.9

* Two alternative market values were used for SO_2 and No_x: low externalities represent \$0 per ton of SO_2 and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO_2 and \$1400 per ton of NO_x.

**TCF = trillion cubic feet

Table 7.3 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of \$50-100/tonne

Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO_2 Removed (Mt)	Incremental NO_x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
	Constant 1995 Gas/Coal Price Differential (\$0.72/MBtu)				
None	134.6	4.9	2.7	147.3	4.9
Low	140.4	6.7	2.8	165.6	5.3
High	106.7	5.0	1.8	130.8	4.2
	Gas/Coal Price Differential in 2010 (\$1.18/MBtu)				
None	109.6	2.5	2.2	108.9	3.8
Low	134.1	5.0	2.7	146.4	4.9
High	123.9	5.5	2.3	147.6	4.7

* Two alternative market values were used for SO_2 and No_x: low externalities represent \$0 per ton of SO_2 and \$700 per ton of NO_x; high externalities represent \$100 per ton of SO_2 and \$1400 per ton of NO_x.

**TCF = trillion cubic feet

Table 7.4 Summary Statistics: Coal to Gas Repowering with a Carbon Permit Price of $101-150/tonne

Externality Cases*	Incremental Carbon Removed (MtC)	Incremental SO_2 Removed (Mt)	Incremental NO_x Removed (Mt)	Affected GW	Gas Consumed (TCF)**
Constant 1995 Gas/Coal Price Differential ($0.72/MBtu)					
None	69.4	4.0	1.2	93.9	2.8
Low	31.0	1.6	0.5	43.8	1.3
High	13.1	0.6	0.2	20.9	0.5
Gas/Coal Price Differential in 2010 ($1.18/MBtu)					
None	117.2	6.6	2.3	148.4	4.5
Low	75.1	4.0	1.2	98.6	3.0
High	29.8	1.5	0.4	41.4	1.2

* Two alternative market values were used for SO_2 and No_x: low externalities represent $0 per ton of SO_2 and $700 per ton of NO_x; high externalities represent $100 per ton of SO_2 and $1400 per ton of NO_x.

**TCF = trillion cubic feet

7.2.4 Cost-Effectiveness

Figure 7.5 portrays the cost-effectiveness of site repowering with NGCC and the corresponding cumulative carbon removed for the two alternative gas/coal price differentials when no environmental externalities are considered. With a price differential of $0.72/MBtu, approximately 30 MtC can be removed for <$50/tC, an additional 135 MtC can be removed for $51-100/tC, and an additional 77 MtC can be removed for >$100/tC. When the price differential increases to $1.18/MBtu, 0 MtC of carbon are removed at <$50/tC, 110 MtC are removed at $51-100/tC, and an additional 132 MtC are removed at >$100/tC.

Figures 7.6 and 7.7 depict the effect of environmental externality credits for SO_2 and NO_x on carbon cost-effectiveness. As mentioned above, in addition to the "no externalities" case, two alternative market values were used for SO_2 and NO_x: low externalities represent $0 per ton of SO_2 and $700 per ton of NO_x; high externalities represent $100 per ton of SO_2 and $1400 per ton of NO_x. The rationale for these values is explained in Appendix G-3. Both Figures 7.6 and 7.7 (together with Tables 7.2 - 7.4) illustrate that the effect of the environmental externality credit is to shift the carbon cost curve downward and to the right causing more capacity (GW) and carbon removal (MtC) to occur at lower carbon permit price levels.

Because dual-fuel plants are already receiving natural gas (although at lower volumes than a repowered plant), a sensitivity analysis was conducted wherein no hook-up or transmission costs were incurred to deliver an increased quantity of natural gas to these repowered plant sites. This "no additional transmission cost case" is illustrated in Figures 7.8 and 7.9, which depict the two alternative gas/coal price differentials and include externality credits for site and steam turbine repowering. Since transportation costs comprise approximately 30% of the total investment cost, the carbon cost curves shift downward considerably when these costs are removed. In Figure 7.8, approximately 45 GW of coal-fired capacity can be repowered at <$50/tC, removing 42 MtC of carbon, 1.2 Mt of SO_2 and 0.9 Mt of NO_x. The amount of natural gas required by these repowered plants is 1.5 thousand cubic feet; approximately 50% of 1995 utility consumption.

The cost-effectiveness numbers derived in this study are optimistic. These numbers should be used with caution because they do not (or do not adequately) consider the following factors that will determine the ultimate cost-effectiveness of the coal-to-gas repowering:

- Potential increase in gas prices from NGCC repowering,
- Actual cost of repowering the candidate coal-fired power plants,
- Excess transmission capacity, and/or economies of scale in delivering the required gas,
- Capacity utilization of the converted plants,
- Costs associated with breaking long-term coal contracts, and
- Other socioeconomic factors (e.g., differential state/federal tax effects, displaced coal miners).

In addition, the effectiveness of repowering as a carbon control strategy will depend on whether and to what extent the converted plants are dispatched. If, because of the costs associated with conversion, the repowered plants are not dispatched or their utilization is minimized, the associated carbon reductions will depend on the fuels and technologies used at the plants dispatched ahead of the repowered plants.

Figure 7.5 Carbon Curve for Coal/Gas Site Repowering: No Environmental Externality Credits

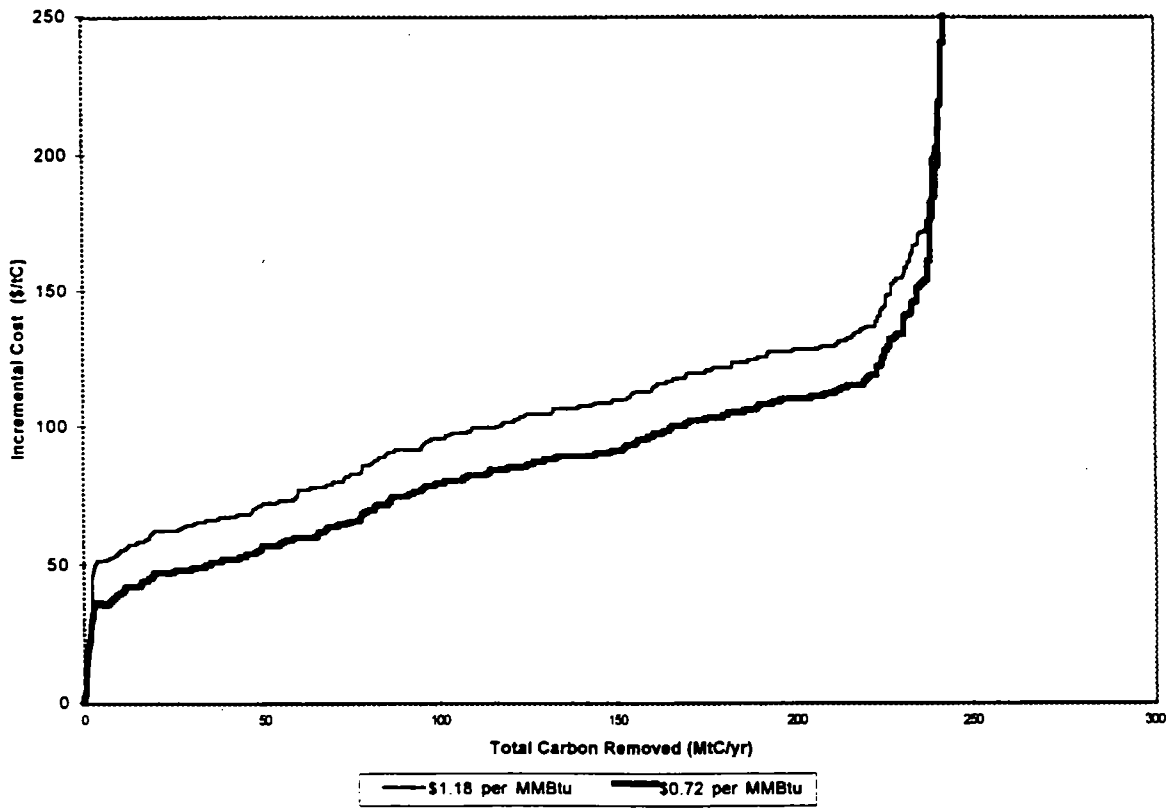


Figure 7.6 Carbon Curve for Coal to Gas Site Repowering: Effect of Environmental Externality Credits on Cost of Carbon Removal with Constant 1995 Gas/Coal Price Differential ($0.72/MBtu)

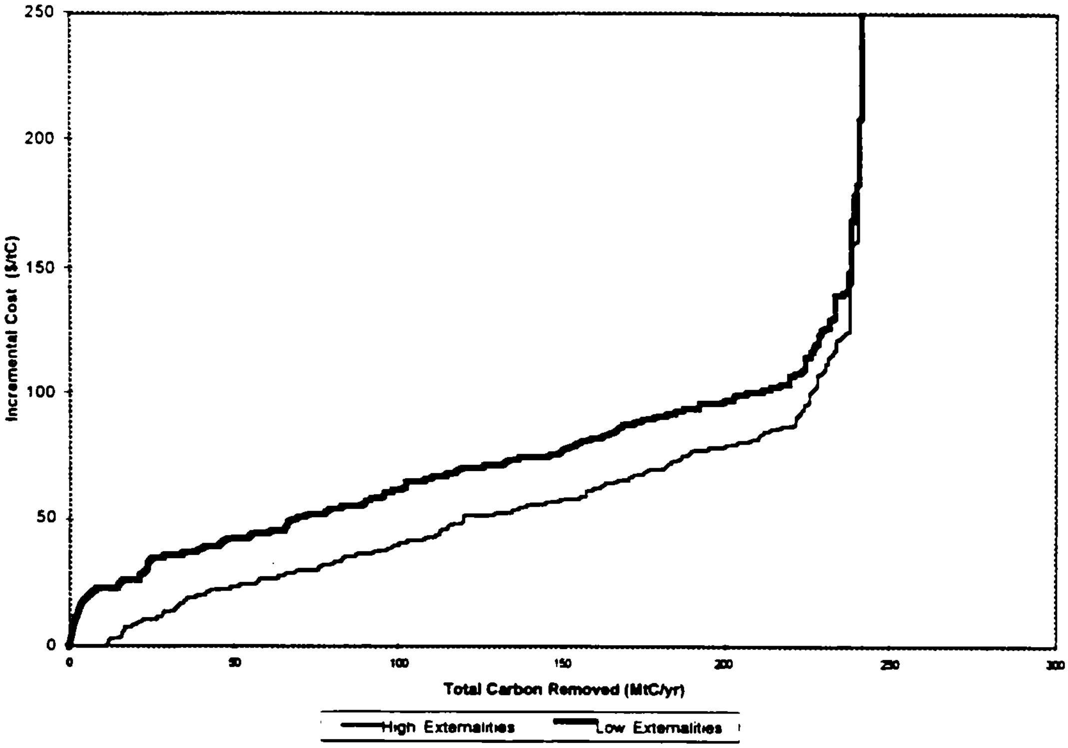


Figure 7.7 Carbon Curve for Coal to Gas Site Repowering: Effect of Environmental Externality Credits on Cost of Carbon Removal with Gas/Coal Price Differential in 2010 ($1.18 MBtu)

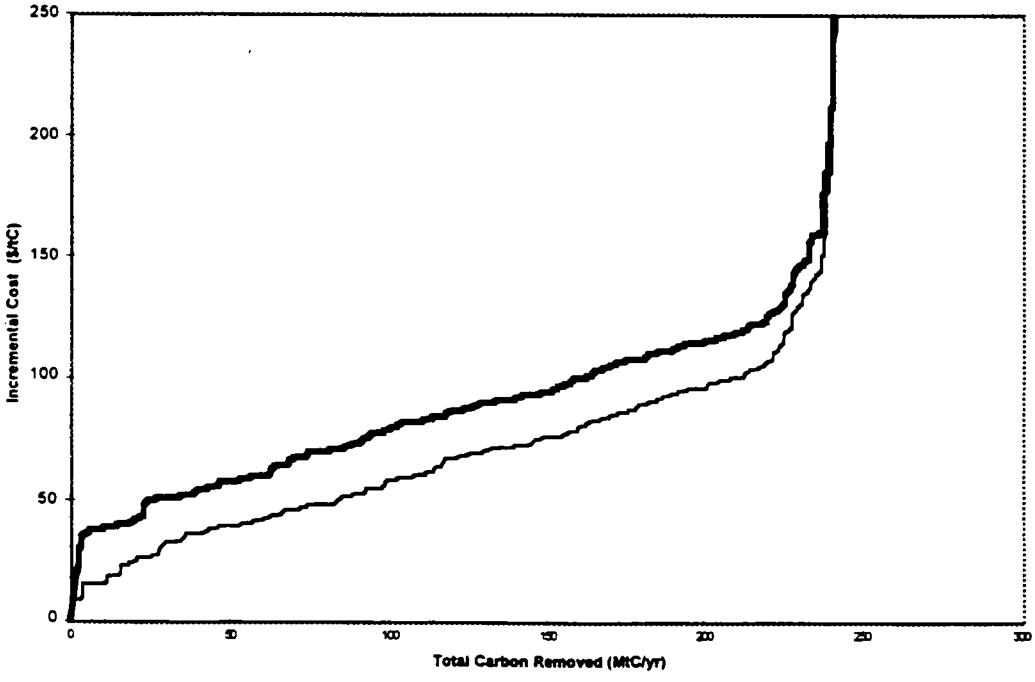


Figure 7.8 Carbon Curve for Partial Repowering[7]: Constant 1995 Gas/Coal Price Differential ($0.72 MBtu) Low Environmental Externality Credits

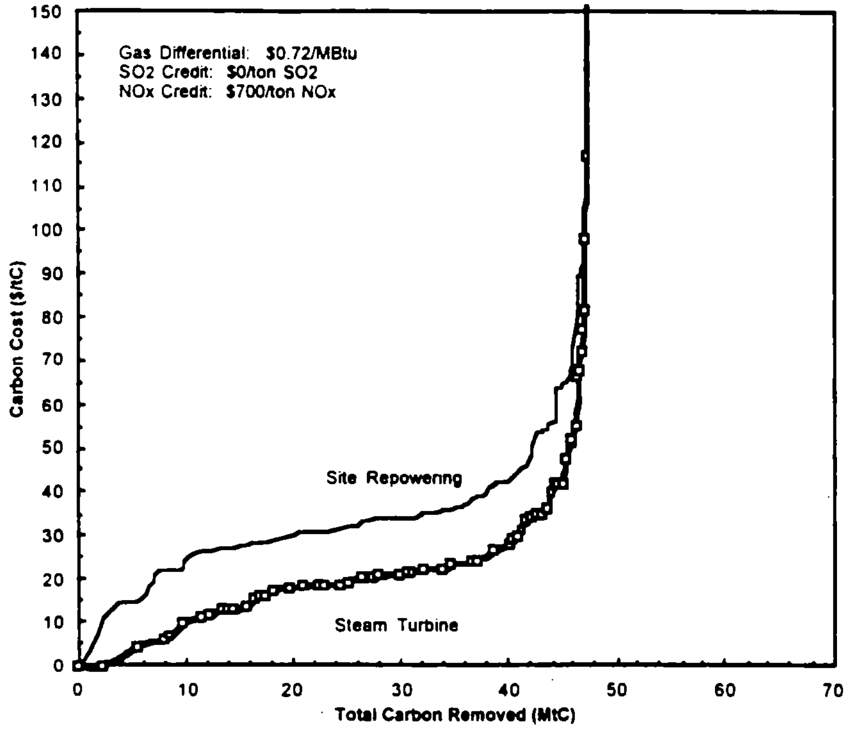
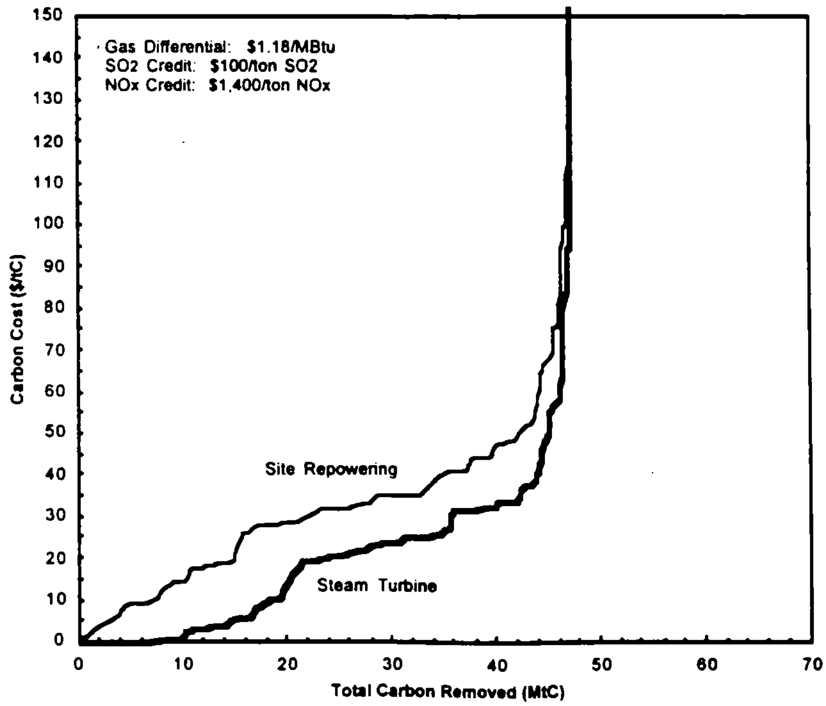


Figure 7.9 Carbon Curve for Partial Repowering[7]: Constant 2010 Gas/CoalPrice Differential ($1.18 MBtu) High Environmental Externality Credits



7.3 RENEWABLE ELECTRICITY TECHNOLOGIES

Over the long term, renewable energy technologies are likely to play a crucial role in limiting carbon emissions and global warming. While aggressive energy efficiency and fuel switching can reduce domestic carbon emissions to approximately 1990 levels by 2010, controlling or reducing carbon emissions beyond that date will require greater energy contributions from low-carbon technologies such as renewables. In other words, renewables will play an essential role in helping the United States to cut carbon emissions in the years beyond 2010.

Renewables will also make important contributions to both domestic and international carbon emission controls by 2010. Renewable technology contributions to domestic electricity and carbon savings in 2010 under the HE/LC scenario are summarized in Table 7.5.

Table 7.5 Additions to Generating Capacity Electricity and Carbon Emission Reductions from Renewables for the HE/LC Case in 2010

Renewable Technology	Capacity Additions (GW)	Electricity (TWh)	Carbon Emission Reduction (MtC)[a]
Included in Scenario:			
Biomass Cofiring	8-12	58-88	16-24
Wind	8-23	28-81	6-20
Hydropower	10-16	23-35	3-5
Subtotal			25-49
Excluded from Scenario:			
Landfill Gas[b]	3-7	20-50	25-53
PV	3-5	6-10	1-2
Geothermal	6-14	47-110	6-16
Solar Thermal	0-2	0-6	0-1
Subtotal			32-72
Total	38-79	182-380	57-121

[a] These carbon emissions reductions represent the difference between the high-efficiency/low-carbon case and the business-as-usual forecast for 2010.

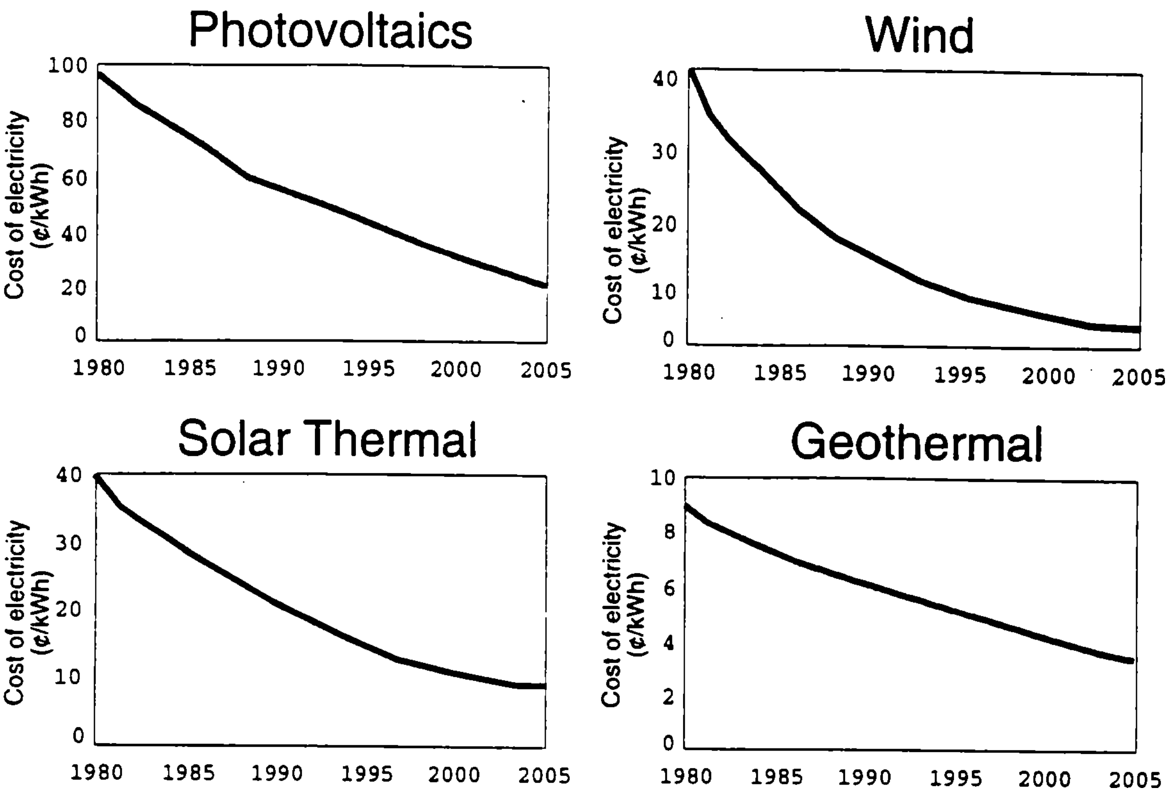
[b] The carbon emission reduction in this case represents the equivalent derived from the prevention of the methane release coupled with its radiation-trapping properties.

This section examines the potential for renewable electricity technologies to reduce U.S. carbon emissions. The contributions of renewables in various end-use sectors, such as transportation, are discussed in other chapters in this report.

Renewables are in the midst of a major, long-term transition, from being "advanced technologies" with only a peripheral market role to becoming mainstream "technologies of choice" in the energy marketplace early in the next century. One clear marker of this transition is the changing cost of electricity from renewable power technologies. Figure 7.10 displays these costs for the period from

1980 to 2005, based on both historical data and recent projections (Office of Utility Technologies, 1997).

Figure 7.10 Historical and Projected Costs of Electricity from Four Renewable Power Technologies



The pace and timing of this transition is difficult to project, however, because it is strongly dependent on such variables as the progress made through research and development, the evolution of energy economy policies, and the magnitude and impact of consumer interest in "green" energy. For example, under the $50/MtC cost-of-carbon scenario assumed in this study, the adoption of wind power in the United States is likely to increase rapidly on an economic basis. In addition, increasing attention is being focused on consumer interest in green energy. As the electric utility sector moves toward competitive markets, consumers probably will have the option of purchasing power that is environmentally cleaner.

The rate of change will impact the role of renewables in 2010 at least as much as the specific energy contribution of renewables in that year. Therefore, this section discusses the trends as well as the predicted contributions of renewables to the energy supply and to carbon emission reductions in 2010.

A thorough analysis of the role of renewables in 2010, which captures the complexity of their transition, has not been conducted as a part of this study. Instead, this section presents analyses of a few renewable technologies whose role is likely to be quite significant by 2010, and includes a general discussion of the other renewable technologies. A more thorough analysis of the relationship between renewables and reductions in carbon emissions over a longer time frame is the subject of a future study.

Thus, this section discusses the role of renewables in two time frames: (1) developments and contributions by 2010, and (2) the long-term outlook.

7.3.1 Renewable Electricity in 2010

As stated earlier, renewable electric technologies will make important contributions to carbon emission reductions in 2010 in the context of a policy that imposes a $50/tonne cost on carbon emissions. Estimates of those contributions are presented here. While the scope of this study did not include a thorough and systematic analysis of this issue, the estimates given are based on a number of directly relevant studies. These include, in particular, carefully developed performance and cost projections for renewable electric technologies (Office of Utility Technologies, 1997) and projections of future market penetrations of these technologies (Office of Energy Efficiency and Renewable Energy, 1997).

The potential of biomass cofiring was assessed because that technology provides an opportunity for reasonably straightforward displacement of a significant amount of coal. This assessment, which draws upon another recent analysis, is presented first.

An analysis of the impact of a $50/tonne cost of carbon on wind power was also conducted, and those results are discussed second. Wind was selected because cost projections for wind power indicate that this technology will be competitive with other electricity generation sources according to the electricity costs modeled in the HE/LC scenario of this study. In addition, wind power is already successfully penetrating electricity markets in the United States and abroad.

This analysis is followed by estimates of carbon emission reductions that would be likely to result from hydropower upgrades and landfill gas capture and use. These estimates are derived from DOE and EPA studies relevant to market projections for those two technologies, respectively (Rinehart et al., 1997; EPA, 1993).

Finally, other key renewable power technologies are discussed briefly. We present estimates of the likely contribution of these technologies in 2010, developed through comparisons and extrapolations from earlier projections (Office of Energy Efficiency and Renewable Energy, 1997).

7.3.1.1 Cofiring Coal with Biomass

Cofiring biomass with coal has the technical and economic potential to replace at least 8 GW of the nation's coal-based generating capacity by 2010, and as much as 26 GW by 2020. Though the current substitution rate is negligible, a rapid expansion is possible with the use of wood residues (urban wood, pallets, and secondary manufacturing products) and dedicated feedstock supply systems (DFSS) such as willow, poplar, and switchgrass.

The current coal-fired power-generating system represents a direct opportunity for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that biomass can replace up to about 15% of the total energy input with little more than burner and feed-intake system modifications to existing stations (CONEG, 1996). Since large-scale power boilers in today's 310-GW-capacity fleet range from 100 MW to 1.3 GW, the biomass potential in a single boiler ranges from 15-150 MW.

Preparation of biomass to an appropriate size of less than one-quarter inch, with a moisture content of less than 25%, can be achieved using existing commercial technologies. "Tuning" the combustion output of the boilers causes little loss in total efficiency, implying that the biomass-to-electricity combustion efficiency is close to the 33-37% range of an unmodified coal plant, an efficiency that stand-alone biomass generating capacity has yet to demonstrate.

Economics

The cost of implementing biomass cofiring varies from site to site. It is influenced by the space available for yarding and storing the biomass, the installation of size-reduction and drying facilities, and the nature of the boiler burner modifications required. The cost is expected to be in the range of $100-$700/kW of biomass capacity. Early trials indicate that a median value of about $180/kW is likely. A 100-MW coal plant with 10% biomass substitution would then require an investment of $1.8 million. There is an O&M cost increase of $70,000/year over coal, as a result of the need for an additional yard worker to handle the biomass. Assuming a GENCO recovers its investment cost in three years, the annual fuel offset then has to be $670,000 to cover capital recovery ($1.8 million) and increased O&M costs ($210,000 for three years). If the average price of coal is about $1.40/MBtu (million Btu), the annual fuel cost of coal is $1.081 million (10 MW of biomass capacity at 85% capacity factor and 32.9% thermal efficiency, 10,337 Btu/kWh). The allowable cost of biomass then is $411,000, or about $9/tonne. Above this cost, the biomass would have to be subsidized to encourage a GENCO to use biomass cofiring.

Fuel Costs

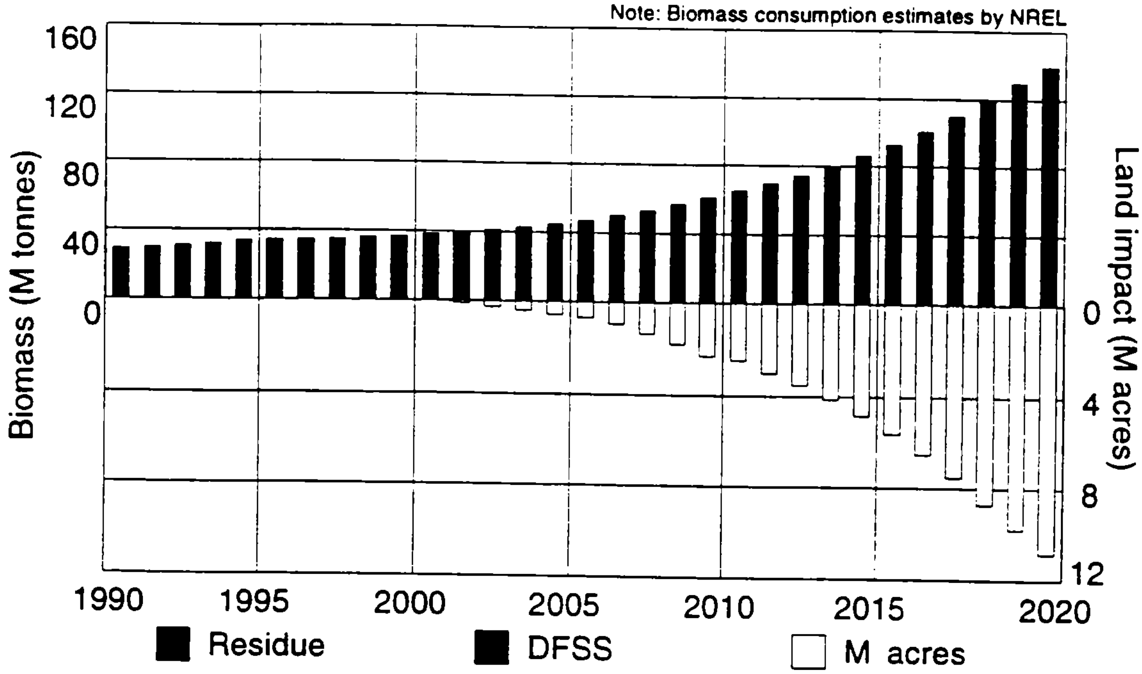
Near-term potential biomass feedstocks are those residues available within a radius of about 50 miles around a plant. Data from existing biomass power plants in the Northeast and California indicate that there are extensive sources of biomass residues available for about $0.50/MBtu (less than $9/tonne). Transportation costs limit the range over which such biomass feedstocks can be acquired and, in the long term, there are likely to be dedicated feedstock systems much closer to the power plants. By definition, residues (e.g., urban wood residues, rights-of-way clearance, construction and demolition wood, pallets, and sawdust shavings from secondary wood processing) are finite and will respond to the prices offered for them.

Dedicated feedstocks would not be bound by this constraint. However, such feedstocks are much more expensive than residues. With current technology the price is about $2/MBtu, although the current development goal is in the range of $1-$1.50/MBtu. It is assumed that an estimated 10.4 million acres will be needed to reach a nominal production of 86 Mt by 2020. Because DFSS is in an early stage of development, the model assumes that the initial planting will yield only about 6 tonnes/acre by 2002 (today's state-of-the-art), and that by 2010 the yield will be closer to 8 tonnes/acre. Today's costs are high; $45/tonne is feasible, but a combination of learning-curve improvements and economies of scale should bring the cost down to about $32/tonne by 2010. The competing coal price is assumed to be $1.40/MBtu ($1.33/GJ) throughout.

Biomass Substitution Potential

The cofiring estimates in this section were derived from a 30 GW scenario for all biomass technologies, developed by NREL for the current Biomass Power Program Strategic Plan. This scenario is for a mix of steam, cofiring, and integrated gasification/combined cycle (IGCC) biomass generation. However, the resource plan that was developed, which included residues and DFSS, is independent of the end use and involves the development of 11-12 million acres of land for DFSS by 2020, or just under 3 million acres by 2010. The resource development shown in Figure 7.11 is used as the basis for this carbon assessment. This indicates that DFSS would come on rapidly after the year 2001 and assumes that residues would be capable of only a small increase in quantity, since much is already being utilized. The average cost of residues is expected to increase gradually, while the cost of DFSS crops is expected to demonstrate a strong learning curve and large economies of scale.

Figure 7.11 30 GW Strategic Plan Scenario



Timing

While a coal-fired station could be modified for cofiring in less than one year (including environmental permitting), a biomass resource assessment, contractual arrangements, and logistics for biomass residues could take the better part of 18 months, based on actual project experience. Although the availability of residues is assumed to be significant and would ultimately supply about 50 Mt, price and availability are likely to be variable. The price will no doubt increase with the level of demand; therefore, the biomass feedstock supply is expected to be a blend of DFSS and residues.

The DFSS component is predicated on making a start on land accumulation (whether purchases, leases, or cooperatives), with land preparation and planting in 1999. A significant effort will be required to initiate development of the 11-12 million acres proposed for 2020; today, discussions are about DFSS demonstrations at the 1000-acre level. Adequate clonal material and management systems for planting, tending, and harvesting will also need to be developed. The crops of choice in much of the Northeast and Southeast are probably woody species, which would require extensive nursery activity to put the needed clonal material in place for planting out. With willow, the first harvest cycle would be four years after planting and a rotation of three years thereafter. For poplar, the cycle is likely to be in the range of six to eight years.

Environmental Issues

Because biomass generally contains significantly less sulfur than coal, cofiring with biomass could reduce SOx emissions. Early results suggest that there is also a NOx reduction potential using woody biomass. However, most coal-fired power stations have efficient precipitators and some have sulfur-capture technologies, so the net environmental effect of 10% biomass substitution (on an energy basis) appears to be negligible. The solid wastes (ash) would be little changed in either composition or mass (most biomass has considerably less ash than coal). But some stations sell fly ash to Portland cement manufacturers, so there may be a need to negotiate the acceptance of mixed biomass and coal ash in such applications with respect to ASTM standards.

The DFSS environmental impact is dependent on the choice of lands for plantations. Replacing annual cropland with perennial DFSS appears to result in a net environmental gain. Results for pasture land are probably negligible and replacement of forest may result in some increased impacts.

The use of residue has the potential to offset landfilling as well as potential methane emissions from landfilling clean biomass materials. Experiences in California indicate that the issue will be one of rationalizing the cost distribution between the waste generator, the hauling contractor, and the generating station receiving the residue rather than it going to a landfill. If such negotiations were successful, and the generating station could guarantee reception of the residues at all times (many urban wood residue generators do not have storage facilities), both residue costs and their availability could improve significantly.

Impact on Carbon Emissions

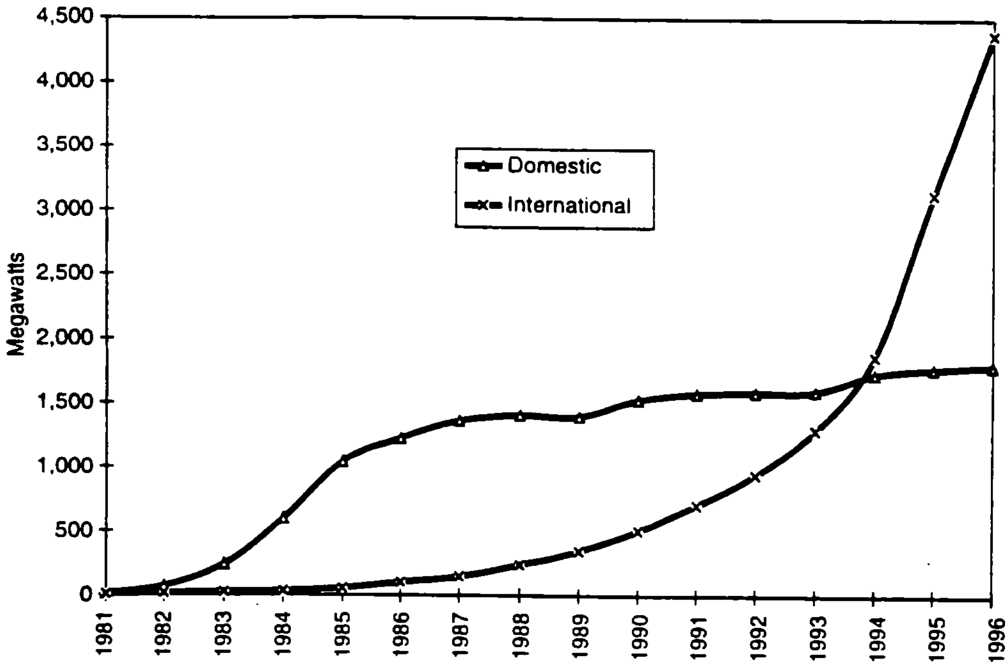
Given the technical and economic potential described above, it is probably reasonable to assume additional biomass-cofired capacity of 8-12 GW by 2010, which should reduce carbon emissions by 16-24 MtC.

7.3.1.2 Wind Power

The development of wind power systems has progressed quite rapidly since 1980. There are approximately 1800 MW of wind capacity operating in the United States today, and another 4300 MW of capacity overseas (Figure 7.12). This capacity growth is almost certain to continue because of continuing decreases in the cost of wind-generated electricity as well as growing interest in emission-free power derived from local, renewable resources. Figure 7.13 shows the projected cost of wind-generated electricity for wind farms located in Class 4 and Class 6 resource sites (as presented in DOE's 1997 Technology Characterizations). Class 4 sites have average wind speeds of 5.6-6.0 m/s, Class 6 sites have average wind speeds of 6.4-7.0 m/s, both measured at a height of 10 meters. Figure 7.13 also displays the median, 10th percentile, and 90th percentile of electricity generation prices in 2010 based on the HE/LC case described in Chapter 6. As these projections indicate, wind power prices are projected to drop below the median 2010 price for that scenario before 2005. Thus, strictly on a price-of-energy basis, in this scenario wind power will be able to compete favorably with other power sources for several years prior to 2010.

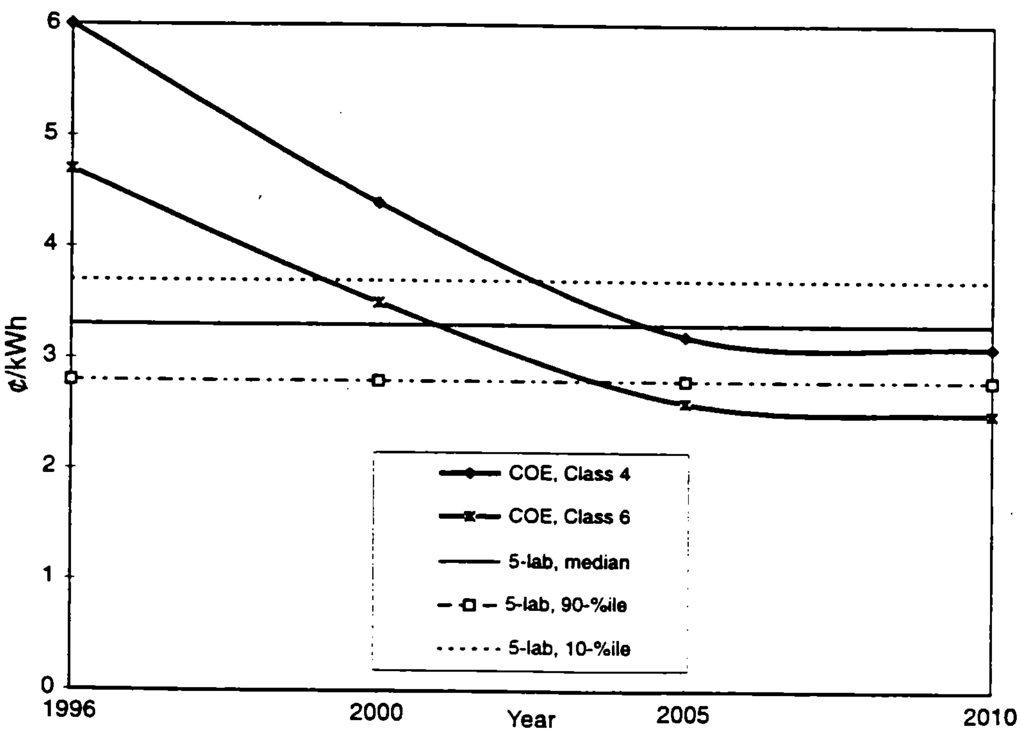
In addition to the price of energy, a number of other factors will affect the extent to which wind power systems will be adopted between now and 2010. These include, for example, the overall market for new power systems, the price penalty that wind power will encounter for providing intermittent power, and the price advantages that wind power will realize because it is a "green" power source and because it is not subject to the risk of future fuel price increases. Because the level of influence of each of these factors has not been analyzed, it is difficult to project their combined impact.

Figure 7.12 Domestic and International Wind Power Capacity, Grid-Connected



Source: Department of Energy, Office of Utility Technologies Wind Division

Figure 7.13 Projections of Wind Power Costs



In the AEO97 reference case forecast, EIA projects electricity generation to increase by about 800 TWh by 2010, from 3083 TWh in 1995 to 3874 TWh in 2010 (EIA, 1996). In this context, EIA projects a total of only 3800 MW of wind generating capacity. The Quality Metrics analysis by the Office of Energy Efficiency and Renewable Energy (EERE) of the impacts of its R&D program estimates that additional installed wind power generating capacity will reach 8 GW and contribute approximately 29 TWh to the electricity market by 2010 if wind program goals are met. This will result in a carbon emission reduction of 6 MtC. Neither of these projections, however, assumes a major new market policy to promote wind power.

In the HE/LC case of this study, electricity generation will increase by significantly less than in the business-as-usual case. Thus, the HE/LC scenario presents a much smaller target market for new power-generation sources. However, under the transition of the utility sector to a competitive market, it is very likely that newer technologies with lower generating costs will displace some existing generation capacity with higher generating costs. Moreover, in the HE/LC scenario, generation costs are projected to be more than 25% higher than in the base case. Thus, as illustrated in Figure 7.13, wind power generation costs will be highly competitive in this marketplace, so displacement of higher-cost existing generation by wind is likely. In an attempt to model the penetration of wind under these conditions, the ORCED model was run using the wind technology characteristics developed by the Office of Utility Technologies (Office of Utility Technologies, 1997). As might be expected, the results indicated that the level of wind penetration in this case is quite sensitive to the actual input parameters. According to the model, for example, using the cost and performance characteristics projected by DOE for the year 2005 could lead to the adoption of as much as 50,000 MW of wind power by 2010. Using 160 kg/MWh, the average carbon intensity of the generation displaced (see Chapter 6), this would result in a carbon emission reduction of 28 MtC. Because the ORCED model indicated that this new wind capacity would displace coal-fired generation, a higher conversion ratio (275 kg/MMh) is used to estimate carbon emission reductions, resulting in an estimated reduction of 48 MtC.

This level of penetration would require wind-turbine manufacturing capacity to expand at a rate of approximately 25% per year. As Figure 7.12 indicates, this level of wind capacity expansion has been reached in the past. Europe's experience with wind power also indicates that this technology can expand quite rapidly. It is possible for the manufacturing industry to respond quickly to market demands, since most of the components of wind systems (generators and gearboxes) are readily available, and not specific to wind technology. In 1991, the European Wind Energy Association set a goal of 4 GW of wind by 2000. This goal has been realized already in 1997, and the new targets are 8 GW by 2000 and 40 GW by 2010. Given that Europe is a much more land-constrained continent with generally lower wind resources than the United States, this comparison suggests that 50 GW of wind power capacity can be realized in the United States by 2010 in the context of a strong policy environment.

The HE/LC context of this analysis assumes a policy environment that acknowledges the need to address global warming. In such an environment, renewable energy, including wind power, will be able to demand somewhat higher prices because of consumers' preferences for green power. The value of that premium is not yet known.

It is well-documented that wind resources in the United States are quite extensive. For example, an assessment of wind resources and access to transmission indicates that more than 115 GW of Class 5 and Class 6 sites are within 5 miles of existing lines, and more than 1,000 GW Class 4 sites are within that same range (Parsons et al., 1995). This assessment excludes sites that are not suitable for wind farm development, such as cities and wilderness areas. Thus, 50 GW could probably be developed primarily in Class 5 and Class 6 areas, which means that they will operate with relatively high capacity factors and low costs of energy. (The Draft Technology Characterizations indicate that capacity factors will be 45% in Class 6 regions and 35% in Class 4 regions by 2005.)

This analysis does not take into account the fact that wind-generated electricity will probably face at least a partial price discounting because wind power is not fully predictable. At this time, the level of this discounting is simply not known. To date, with low levels of penetration into grid-connected generation, intermittency has not been an issue. There are some indications that the range of electricity prices in a competitive market will be fairly narrow. For example, prices for electricity transactions on the Continental Power Exchange during peak hours generally vary only by about 2 cents/kWh (Continental Power Exchange, 1997). This implies that price variations between different generation sources cannot vary by more than that, and it is likely that the difference will be much smaller under full competition.

In summary, analyses indicate that total wind power capacity in 2010 could range from as low as 5 GW, based on a simple extrapolation of today's energy economy, to as high as 50 GW in an environment that includes competitive pricing and policies emphasizing control of carbon emissions. Given these results, it is probably reasonable to estimate that additional wind capacity will be 8-23 GW in 2010. This translates into electricity contributions of 28-81 TWh, resulting in reductions of carbon emissions of 6-20 MtC relative to the BAU forecast for 2010.

7.3.1.3 Increasing Generation and Capacity at Existing Hydropower Plants

Hydroelectric power currently supplies about 10% (78 GW) of the nation's electricity and constitutes 84% of the nation's generation from renewables (EIA, 1996). Hydroelectric power plants produce no greenhouse gas emissions during operation (DOE, 1994). In the 1940s, 40% of the country's electricity came from hydropower plants (Williams and Bateman, 1995). The adverse environmental affects of some hydropower projects are now relatively well known (e.g., Mattice, 1991), but significant progress is also being made in mitigating these problems (Sale et al., 1991).

Hydroelectric power uses the energy of falling water to generate electricity. Hydroelectric generation technologies for utility-scale applications are generally considered to be mature, with turbine efficiencies typically in the 75%-85% range (OTA, 1995). There are three types of hydropower facility:

1. Most hydropower plants use dams to raise the water level, which increases the water's potential energy, and allows for regulation of the water availability. Conventional hydropower (with reservoir storage) can provide baseload, intermediate, or peaking power, depending on the availability of water and project design (OTA, 1995).

2. Run-of-river systems do not use large dams or storage reservoirs. Instead, smaller diversion structures are used to channel some of the water through a canal or penstock to a powerhouse, after which the water is returned to the river. Run-of-river systems avoid some of the costs and environmental impacts associated with large hydro facilities.

3. Pumped storage projects use off-peak electricity (usually from a baseload power plant) to pump water to an upper reservoir; this water is later released to flow through a generator during periods of peak demand. Such plants are net consumers of energy. Although pumped storage is not a renewable energy technology, it can result in a net reduction in greenhouse gas emissions when the fuel providing electricity for pumping has a lower carbon content than the fuel being displaced by the pumped storage generation (DOE, 1994).

The main challenge for hydropower in recent years has been the growing concern over its local environmental impact. By damming rivers to create storage reservoirs, hydro facilities can have an adverse effect on terrestrial and aquatic ecosystems. Wildlife habitats can become inundated. Fish migration routes can be cut off, and fish can die in the generating turbines or because the downstream water quality and habitat are changed. Plants that grow along the riverbanks can be disrupted by changes in the natural water level, both above and below the dam, and large or rapid variations in the amount of water being discharged can disrupt aquatic habitats and accelerate erosion downstream.

Regulatory measures — such as the licensing of non-federal hydropower projects and the Endangered Species Act — are reducing the environmental impact of hydropower projects, but they are also reducing total electricity production from this energy source. Between 1995 and 2010, 19 GW of hydropower at non-federal projects will be subject to relicensing. Recent trends indicate that relicensing results in an average 8% loss in generation due to the imposition of new environmental constraints on operation.

Under the HE/LC scenario, and assuming a sustained regulatory reinvention effort between now and the year 2010, incentives could be in place to increase hydroelectric power generation in either of two ways. Neither of these opportunities involves the construction of hydropower plants at new sites. However, both will require continued R&D to improve the design of turbine systems and to minimize adverse environmental effects:

- Increasing generation at existing hydropower plants. This option consists of modernizing and upgrading existing turbines and generators to increase their efficiency and/or electrical output. With enabling incentives, upgrading hydropower plants can result in energy production gains of 5%-10%. Hydropower upgrades would also have significant environmental benefits, because new generating technologies offer improved fish passage, better water quality, and new opportunities for improving downstream aquatic habitats.

- Adding generating capacity at existing dams. A recent resource assessment identified 20 GW of undeveloped hydropower capacity at existing dams (Rinehart et al., 1997). About 36,000 GWh of new hydropower generation could be added by developing these sites between 1995 and 2010 (Office of Conservation and Renewable Energy, 1990).

Further expansion of hydropower capacity is possible, but unlikely until after 2010. The national hydropower resource assessment (Rinehart et al., 1997) has identified an additional 11 GW of environmentally acceptable hydropower at undeveloped sites (those requiring the construction of new dams or diversions). These resources may eventually be developed, given more advantageous economics, regulatory reinvention, and/or technology improvements. Further development of efficient low-head generating technologies would encourage deployment at the many low-head sites that are currently unsuitable for hydropower additions.

Considering only the near-term options, and the fact that there may be some loss of hydropower capacity due to relicensing issues and environmental mitigation regulations, net capacity additions by 2010 could be 10-16 GW, reducing emissions by 3-5 MtC. Additional carbon savings can be achieved after 2010 with continuing advancements in generating technologies and environmental mitigation techniques.

7.3.1.4 Landfill Gas

When food scraps and other organic wastes in landfills decompose, they produce methane. Methane is a potent greenhouse gas that is also the main ingredient of natural gas. According to the

Intergovernmental Panel on Climate Change, each kilogram of methane is about 21 times more effective at trapping radiation in the atmosphere than a kilogram of carbon dioxide. Landfills are the largest source of anthropogenic methane emissions in the United States; they are responsible for almost 40% of these emissions each year (EPA, 1997).

New EPA regulations require operators to seal larger, closed landfills with a special cap, collect the gas, and burn it to prevent atmospheric releases of methane. But wells sunk into landfills can capture the gas before it escapes the surface. It can then be used for a variety of applications, including generating electricity.

Today, about 165 landfills recover and utilize methane as a fuel. Various estimates (Governmental Advisory Associates, 1994; EPA, 1997) indicate that between 300 and 750 of the country's 3500 landfills could economically recover methane using currently available technologies. The development of more efficient, less expensive technologies for gas recovery, clean-up, and utilization could accelerate the adoption of landfill gas-to-energy systems. For example, highly efficient, experimental fuel cells have operated on landfill gas processed using new clean-up technology.

By 2010, 0.2-0.5 quads of energy per year could be recovered from the methane in landfills and converted to electricity. Taking into account the difference in the radiative effects of methane and CO_2, this represents the equivalent of 25-53 MtC in reduced emissions (DOE, 1994).

7.3.1.5 Other Renewable Power Technologies

This section examines three more renewable electric technologies: photovoltaics (PV), geothermal power, and solar thermal power. Figure 7.10 illustrates that the costs for these three technologies have also decreased sharply over the past 15 years. It is very likely that this trend will continue. While none of these technologies are expected to contribute as much electricity as biomass cofiring or wind power by 2010, their role in 2010 electricity markets may be significant and growing.

Photovoltaics

Photovoltaics (PV) uses solar cells to generate electricity from sunlight without any emissions or moving parts. This technology has made substantial progress since its first successful application in space. While PV power costs are still significantly higher than the costs of other renewable technologies, sales of PV power systems have been growing steadily, probably because of the many unique advantages of PV. These include modularity (applications can range from solar calculators to power stations), widespread applicability (since adequate solar resources are widely available), and ease of integration into the built environment (through incorporation into building facades, roofing materials, highway sound barriers, parking-lot structures, etc.). The most important application of PV today is in stand-alone systems that provide power to remote water pumps or off-grid residences, for example. Because approximately two billion people live in villages without grid electricity, remote power represents a very large and important market for PV in developing countries.

For grid-connected applications, one of the most promising trends in the past few years is "building-integrated" PV. Numerous buildings have been constructed — primarily in Europe, Japan, and the United States — that incorporate PV panels in windows, awnings, or roofing materials. Thus, the PV panels serve a dual function, which effectively lowers the cost of their role as power generators. In these applications, the PV power directly displaces grid electricity at the end point of the delivery system, where it has the greatest value. Another advantage of PV is that its peak power output generally coincides with peak electricity demand, which further enhances its market value.

Worldwide sales of PV power systems have grown to nearly 100 MW per year, up from 10 MW in 1982, an average annual growth rate of about 20%. This rate of growth is likely to increase as a result of numerous programs promoting PV for village power in developing countries as well as programs promoting greater use of PV in several developed nations. One example is the U.S. Million Solar Roofs program, announced by President Clinton at the United Nations on June 26, 1997. Others include Japan's Sunshine Project, Germany's subsidy of up to 70% of PV system costs, and Switzerland's PV Schools Program.

EIA estimates that total installed PV capacity in the United States will be only 0-2 GW in 2010 (EIA, 1996). However, an independent assessment of the impact of DOE's R&D programs indicates that, by 2010, installed U.S. PV capacity will be approximately 1.3 GW under a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). Using this as a starting point, and considering the many advantages of PV, an estimate of installed capacity of 4-7 GW in 2010 is probably reasonable for the HE/LC scenario. This would provide 6-13 TWh of electricity and reduce carbon emissions by 1-2 MtC. One important addition to PV capacity will come from the recently announced Million Roofs Initiative, which will result in 1-2 GW of new capacity.

The market trends for PV in 2010 are probably more significant than its energy and carbon contributions. By 2010, PV energy prices will be substantially lower than they are today, and we will have had considerably more experience with the development and use of building-integrated PV products. In this context, the United States will be moving into a situation in which a significant and increasing fraction of construction includes PV generation capabilities.

Geothermal Electricity

Geothermal power technologies use the thermal energy from underground reservoirs of hot water or steam to produce electricity. With higher temperature resources, the steam is used to drive a turbine directly; with lower temperature resources, a binary technology is used in which the hot water vaporizes another working fluid, which then drives a turbine. These geothermal power-generation technologies are considered fairly mature. The major challenge lies in locating and characterizing the size and longevity of specific geothermal reservoirs.

Approximately 3 GW of geothermal capacity is installed in the United States today. While EIA estimates that geothermal capacity will increase by only 0.2 GW by 2010 (EIA, 1996), DOE's recent Quality Metrics Study indicates that geothermal power capacity will increase by 5.8 GW, and electricity production will increase about 45 TWh, in a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). While a $50/tonne cost of carbon would improve the economics for geothermal, it is not expected to provide as much of a boost as it does for wind or biomass. It is probably reasonable to use the DOE estimate as the lower boundary, and project that total installed geothermal power capacity in 2010 under the HE/LC case will be 8-16 GW. The 6-14 GW increase in geothermal capacity over today's level would reduce carbon emissions by 6-16 MtC.

Solar Thermal Electric Technology

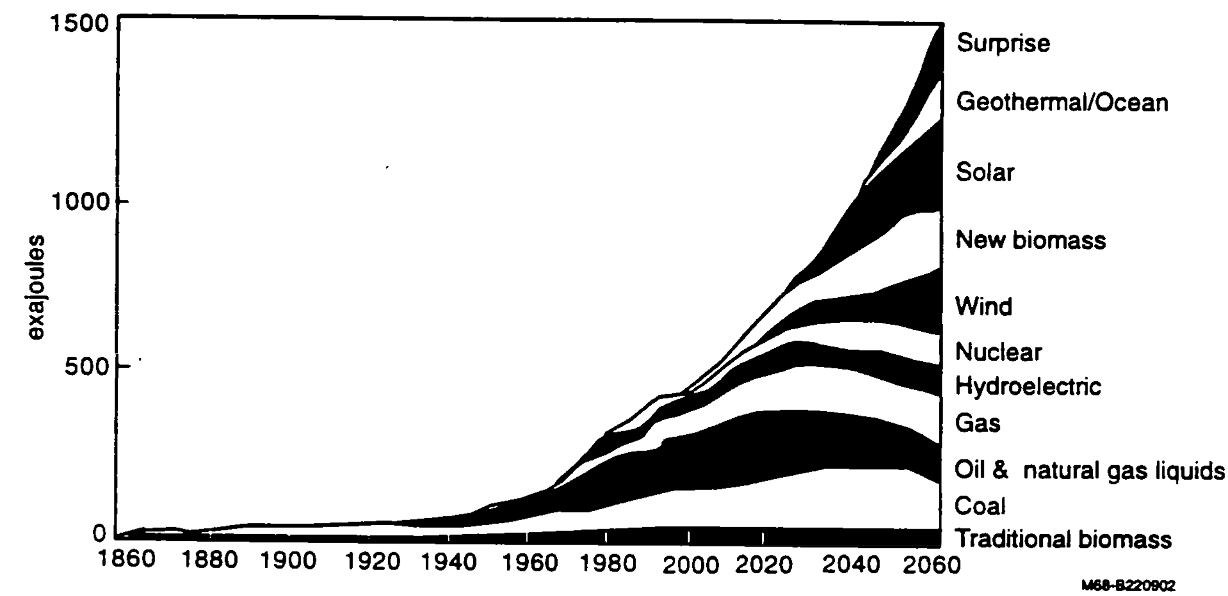
Solar thermal power technologies use mirrors to concentrate direct sunlight onto a thermal receiver, thus creating a high-temperature energy source that can be used with a heat engine to generate electricity. There are three types of solar thermal power systems: parabolic troughs, power towers, and dish/engine systems. Parabolic trough systems use large fields of linear parabolic reflectors, each of which heats a fluid flowing through a receiver pipe located along the focal line of the reflector. About 350 MW of these systems are operating in California. A 10-MW demonstration of a solar thermal power-tower system, which uses large mirrors to direct solar rays to a thermal receiver atop a tower, is also operating in California. The third technology uses individual parabolic dish reflectors to provide thermal energy to a Stirling engine mounted at the focal point of the dish. A few individual prototype units, which have power outputs of about 10-25 kW each, are being tested in the United States.

While EIA projects negligible gains for solar thermal generating capacity by 2010 (EIA. 1996), DOE's recent Quality Metrics Study suggests that solar thermal systems will provide approximately 2 TWh of electricity in 2010 in a BAU scenario (Office of Energy Efficiency and Renewable Energy, 1997). Under the HE/LC scenario of this study, an estimate of 0-2 GW capacity and 0-6 TWh electricity generation in 2010 is probably reasonable. This would reduce carbon emissions about 0-1 MtC.

7.3.2 The Long-Term Role of Renewables

As indicated at the beginning of this section, it is quite likely that renewable energy technologies will play a crucial role in limiting carbon emissions and global warming in the long term. Continued domestic and international economic development that does not foster further global warming will require greater energy consumption coupled with lower carbon emissions. The only options are thus low-carbon energy supplies, such as nuclear power or renewables, or the sequestration of carbon emissions from the use of fossil fuels. With the continuing technological development and cost reductions of renewables, renewables may become preferred energy resources some time within the next one to three decades. Moreover, they will probably expand to become the world's primary energy resource in the latter half of the next century. In fact, just such a transition was suggested recently by Shell International (Figure 7.14) (Royal Dutch/Shell Group of Companies, 1996).

Figure 7.14 Sustained Growth Scenario from Shell International (Reproduced courtesy of Shell International Petroleum Company)



This subsection describes the future direction and likely accomplishments of continuing R&D in renewables. This discussion should lend credence to the prediction that non-hydro renewables will make the transition from a minor to a major contributor to the world's electricity supplies.

Biomass Power

The most important R&D areas for biomass power are in gasification/conversion systems and in feedstock production. Gasification involves converting the solid biomass feedstock material to a gas that is cleaned and then burned in a combustion turbine or used in a combined-cycle plant. This technology is currently in the initial demonstration stage of development.

The importance of this technology is that it can take advantage of advanced turbine designs and heat-recovery steam generators to achieve almost twice the efficiency of currently installed biomass technologies (NREL estimates, 1997). High-pressure gasification technologies yield the highest efficiencies, but they also require the development of efficient, cost-effective methods for cleaning the hot gases before they enter the turbine.

On the biomass production side, genetic research is likely to produce energy crop species that provide consistently higher biomass yields on an energy-content basis, thus providing a proportional reduction in biomass feedstock costs. Related research into new species designed for better fuel production also looks promising in terms of significantly decreasing biofuels costs over time. Research into advanced agricultural methods will also lower feedstock production costs over time. Finally, the development of simpler feedstock handling and processing methods will also lead to lower costs. Whole-tree processing methods, for example, which avoid the cost of chipping the wood before processing or use, could reduce the cost of harvesting and delivering the biomass to the power plant by about one-third (OTA, 1995).

Taken together, improvements in biomass power conversion as well as feedstock production and processing could reduce the cost of electricity from biomass to about 3-4 cents/kWh. This would make biomass power very economical in comparison to other mainstream electricity sources. As biomass power expands, most of it will employ dedicated feedstocks. In this context, biomass use will entail low net carbon emissions. These net emissions primarily result from the combustion of fossil fuels in production and delivery, because the carbon emitted during conversion will be reabsorbed as new feedstock grows. Thus, biomass power can become a major contributor to reducing overall carbon emissions from electricity generation in the coming decades.

Wind Power

The technological and economic feasibility of wind power — both in the United States and abroad — has already been well established, as the wind generation capacity curves in Figure 7.12 indicate. Nonetheless, major advances for wind power technology in both the short-term and long-term are likely. These are predicted for the short-term by DOE's cost and performance projections (Office of Utility Technologies, 1997), as illustrated in Figure 7.13.

Wind turbine design is the most critical R&D area. In general terms, the research goals are to produce turbine designs that have half of the material content of today's turbines, at perhaps three-quarters of the material cost (to account for more expensive materials), but with higher efficiencies and longer lifetimes. Such design improvements will not only lower the cost of wind-generated electricity, they will also make it economically practical to utilize the widespread, somewhat lower quality wind resources found in Class 4 wind regimes. Some of the critical research needed to achieve these goals includes continued empirical research into the air-turbine blade interface, computational fluid dynamics modeling of that interaction, and fatigue testing and structural modeling coupled with materials research. This is all aimed at producing more efficient turbine blades that minimize material utilization while extending blade operating lifetimes.

Another important area of R&D concerns the development of direct-drive generators and improved power electronics. This will yield higher conversion efficiencies and more durable power-conversion components, eliminating the need for a gearbox in the drive train. A major challenge will be the integration of advanced components and controls into large-scale, utility-class hardware.

There is also considerable room for improvement in turbine manufacturing processes through process development and automation, since today's turbine blades are still largely built by hand.

A fourth critical research area is that of wind prospecting and prediction. Wind regimes are extremely site-specific, so even though wind resources have been broadly categorized for the nation and the world as a whole, the siting of individual wind farms requires detailed information in order to select the best site. Wind speeds can vary dramatically over the course of seconds (due to turbulence), hours (diurnal variations), days (weather fronts), and months (seasonal variations). The best locations are those with strong, sustained winds having little turbulence. Finding such locations requires extensive prospecting and monitoring (OTA, 1995). The development of better tools for resource characterization and prediction will both improve the economics of wind power and enhance its value by enabling utilities to more reliably predict the power output from specific wind power plants.

Another important thrust for research is to address siting issues. For example, the tops of ridges are often good wind sites, but such a visible location for a wind farm can be a cause for concern when the site is either close to a population center or in an area of particularly great scenic value. To date, there have been virtually no studies to understand the local values associated with the visual impact of wind systems relative to other energy technologies in the United States. Yet such analysis could play a key role in decisions about the adoption of wind power in specific regions. Another environmental consideration affecting site selection is the potential risk to birds, particularly raptors, which sometimes fly into the rapidly turning rotor blades. This, too, seems like an issue that may well be resolved through research to understand the scope of the problem relative to other threats to bird species as well as the development of ways to keep birds a safe distance from moving turbine blades.

In summary, the research front for wind power technology is very broad. Achievements are likely to lead to widespread adoption and application of this electric power technology throughout the world, wherever resources are adequate, over the next few decades.

Geothermal Electricity

Both current geothermal power systems and advanced geothermal power technology concepts will benefit from continuing R&D.

Today's geothermal power plants use the thermal energy from hot water and steam in hydrothermal reservoirs to generate electricity. While the power conversion and drilling technologies related to these power plants are considered relatively mature, they will also benefit from R&D in heat exchangers, hot fluid management systems, and new thermal conversion cycles. These activities alone could result in energy cost reductions of at least 20% in the next few years (NREL estimates, 1997).

The most important R&D area for conventional geothermal technology is resource exploration and characterization. The cost of geothermal electricity is highly dependent on resource characteristics such as temperature, depth, sustainable extraction rate, fluid chemistry, and ease of drilling. By 2020, improvements in drilling technology, advanced seismic data gathering, and better computer modeling and interpretation of the data could lower the average cost of locating and assessing geothermal resources by 50% (NREL estimates, 1997).

In the long term, geothermal power plants could make use of hot dry rock resources — areas of exceptionally hot rock (above 150°C) that have little or no water in them. Energy can be extracted from these zones by injecting water from the surface underground, where it is heated. Although the engineering feasibility of extracting energy from hot dry rock has already been demonstrated (Secretary of Energy Advisory Board, 1995), further R&D is necessary to make the technology commercially viable. With success in that endeavor, the potential for geothermal power would be vastly expanded because hot dry rock resources are widely available.

Photovoltaic Power Systems

Although PV power technology has already experienced major gains in both performance and economics as a result of R&D conducted over the past 30-40 years, there is still considerable potential for further improvements. This is true for essentially all aspects of PV power systems, including research on basic photovoltaic materials, development of high-efficiency PV cells and modules, development of better PV power products, lower cost manufacturing processes, and improvements in the various components of PV systems.

A good example of the potential of PV R&D is found by comparing the module efficiencies of current commercial PV modules with the efficiencies of individual solar cells. For crystalline silicon PV technology, the technology representing about 90% of current sales, commercial module efficiencies are generally between 10% and 15%, while the best laboratory cell efficiencies are well above 20%. For thin-film PV technology, which includes amorphous silicon, copper indium diselenide, and cadmium telluride modules, current module efficiencies are generally well under 10%, but cell efficiencies are above 15%. Thus, in all cases, progress in commercial products would be virtually assured through the replication of established laboratory results. There is also clearly the potential for greater increases in cell efficiencies over today's laboratory results. Some of the research tools that are being applied include computer modeling of various semiconductor materials and atomic-level engineering of new devices to better understand their photovoltaic and electronic properties.

Looking ahead, we find that significantly greater efficiencies are possible. For example, multi-junction cells have been tested with efficiencies above 30%. At this time, these are small, laboratory-scale devices whose initial application is expected to be with concentrators, in which the cost of the cell is significantly offset by the increased solar energy captured by the optical concentrator. However, in a decade or two, it is certainly conceivable that low-cost processes for making similar high-efficiency multi-junction devices will have been developed, which will make it possible to use them in conventional, flat-plate PV modules.

In the area of manufacturing processes, considerable effort is being made to perfect processes that provide uniform, high-quality materials for the thin-film technologies. The fruits of these efforts are likely to be realized in the next few years as a number of firms construct fairly large (5-20 MW per year) manufacturing plants based on the results of process research and development.

There is still considerable progress to be made in the development of PV power products. For example, many PV power systems today are still being individually designed for specific applications. Off-the-shelf PV power systems and consumer products (such as PV walk-lights, lanterns, and battery chargers) are becoming more available, but the commercial PV industry is still a long way from making it as easy to purchase a residential PV system as it is to buy a refrigerator. The development of products that are readily applied to such individual needs will have an important effect on PV electricity costs because it will increase the volume of sales. A particularly important set of PV products is likely to be PV components for building shells. These include windows, wall materials, awnings, and roofing materials that incorporate PV and are as readily installed as the components they replace in today's building industry. A reasonable long-term target is to have a large fraction of new construction incorporate such building-integrated PV products.

Finally, we will continue to see improvements in the balance-of-system components of PV systems. Examples include power conditioners and controllers, which serve as the electrical operating and interface system for integrating PV power modules with the load and/or the power grid. These components will continue to improve as well as benefit from developments in power electronics. Greater system integration is also likely, simplifying overall system design. A good example is the development of PV modules that incorporate dc-to-ac inverters, an activity that is currently under way.

In summary, PV technology will benefit from major R&D advances for many years to come, and these advances will significantly improve the economics of PV power. Among the implications of these advances, it is likely that PV power systems will reach prices of $3000/kW by 2010, which is less than half the current average price. Further price reductions will no doubt occur beyond that.

Solar Thermal Electricity

Solar thermal technologies will benefit from R&D in a broad range of areas. For example, successful development of durable silver/polymer reflectors will reduce reflector costs by 25% to 50% for all three technologies, reducing system costs by 10% to 20%. Improved reflectors and receivers will also allow higher operating temperatures and thus higher solar-to-electric conversion efficiencies. Technology advances for Stirling engines will directly benefit dish/engine systems; one of the most important areas is the extension of operating lifetimes between overhauls. The development and application of hybrid solar/natural gas systems will be particularly important for power tower and parabolic trough technologies. These will make it possible to provide dispatchable power and to use combined-cycle technology, as well as smaller solar fields without being penalized by smaller steam turbines, which tend to be less efficient.

By 2020, we are likely to see power-tower conversion efficiencies around 30%, compared with about 15% today, and dish/engine conversion efficiencies of about 35%, up from about 25% in current prototypes. At the same time, these technologies will cost less and be more durable. At this stage, they are likely to be fully competitive with other mainstream power technologies in areas with good solar resources throughout the United States and the rest of the world.

7.4 EFFICIENCY IMPROVEMENTS IN GENERATION AND TRANSMISSION & DISTRIBUTION

Lowering the heat rates of fossil-fueled generation results in greater efficiency (i.e., less fuel burned per electricity generated) and lower carbon emissions. OTA (1991, p. 320), for instance, suggests that improved maintenance could reduce heat rates by 5%, resulting in a reduction of 22 million tonnes of carbon emissions by the year 2000. OTA includes this measure in their "moderate" scenario, viewing it as either a low-cost or a no-cost measure. The rate of improvement assumed by OTA is consistent with a power plant performance monitoring and improvement project conducted by the Electric Power Research Institute (1986; 1989). Hirst and Baxter (1997) also note the value of cutting heat rates for fossil-fuel power plants, as a carbon reduction option. No efficiency improvements to existing fossil plants are assumed in the 1997 *Annual Energy Outlook's* reference case (Schouberlein, 1997).

The Southern Company has had extensive experience with improving the efficiency of their electric utility system. Over a thirteen-year period, the Southern Company was able to reduce its heat rate by 5.8%, lowering it from approximately 10,300 Btu/kWh (in 1982) to less than 9,700 Btu/kWh (in 1994) (Southern Company, 1993; Siegel, 1997). This represents an improvement in fossil system efficiency from approximately 33.2% (in 1982) to 34.8% (in 1994). The current level of efficiency in U.S. fossil-fired power plants is approximately 33%. In addition to improving the company's system-wide heat rate, the Southern Company was able to increase its reliability from 88% (in 1982) to 96% (in 1994) (Southern Electric International, 1996), and was able to increase its availability to approximately 86%. The current availability of U.S. fossil-fired power plants is approximately 81%.

These heat rate and availability improvements to the Southern Company's electric system have provided benefits valued at $1.1 billion/year. One of the largest benefits to the Southern Company has been from the deferral of 6,000 MW of new capacity. The cost of these heat rate and reliability improvements to the Southern Company is estimated at approximately $325 million/year. The operation and maintenance activities that comprise these costs include: establishing a heat rate improvement training program, creation of a plant heat rate review board and a system heat rate technical network, assignment of an efficiency engineer at each plant, instituting a program of heat rate monitoring, and investing in design upgrades (Siegel, 1997).

The Southern Company's experience is consistent with the OTA and EPRI estimate that a 5% heat rate improvement is technically feasible at a low cost or at no cost. Such an improvement would result in a concomitant reduction of 5% in the carbon emissions of the utility sector. Based on Chapter 6's HE/LC case (Table 6.4), the electricity sector's carbon emissions in 2010 would be 492 MtC. Although coal generation accounts for only 46.2% of the electricity generation forecasted for 2010, coal plants account for 81% (or 400 MtC) of the carbon produced by the electricity sector. A 5% reduction would represent 20 Mt of carbon emissions. Assuming that 35-65% of this total is feasible, a realistic estimate of the potential reduction is 7-13 MtC.

Improving the efficiency of transmission and distribution (T&D) systems is another supply-side option available to utilities. As with generation, T&D improvements can include both capital investments (for example, new transformers and conductors) and improved operations. Because T&D losses account for only about 7% of total generation, the opportunities to reduce CO_2 emissions through such mechanisms are limited. However, they could nonetheless be cost-effective. Improving T&D efficiency by 10% would cut emissions by almost 1% (Hirst and Baxter, 1997).

7.5 NUCLEAR PLANT LIFE EXTENSION

In both the AEO97 reference case and the restructured case described in Chapter 6, nuclear plants are projected to lose market share in the national mix of electricity generation. Similar trends are forecast worldwide, with the forecasted decline in nuclear power in Europe being particularly large (South, et al., 1997).

In the U.S., the nuclear power capacity of 99.2 gigawatts that existed in 1995 is projected to drop to 88.9 gigawatts in both the AEO97 reference case and the restructured case in 2010. This drop is primarily the result of the retirement of 17 plants whose licenses expire between 1999 and 2010. The combined capacity of these 17 plants is 11.5 gigawatts. The average capacity factor of the remaining plants ranges from 76-79% throughout the forecast, deviating little from the current capacity factor of 77%.

No additional nuclear units are actively under construction in the U.S. Therefore, no new planned units are assumed to come into service during the 2010 forecast. One nuclear unit, Watts Bar 1 owned by the Tennessee Valley Authority, received its license in 1996, but a few plants have also recently closed.

Nuclear power is a carbon-free source of electricity. Retaining as much as possible of its current power generation would therefore be an important carbon mitigation strategy in an economy where carbon emissions bear a charge of $50 per tonne, as in the HE/LC scenario.

AEO97 defines a "high nuclear case" which assumes that every nuclear plant operating in 1996 has an additional 10 years of operation, as long as their operating costs do not exceed 4 cents/kWh. This 2010 forecast results in the closure of only three nuclear plants (totaling 1.3 gigawatts of capacity) due to license expirations and the addition of 10.2 gigawatts of new capacity from 14 plant lifetime extensions (EIA, 1996; Nuclear Regulatory Commission, 1996). Thus, nuclear capacity in EIA's forecast for 2010 grows from 88.9 gigawatts (in the reference case) to 99.1 gigawatts (in the "high nuclear case"). Based on a capacity factor of 77%, this 10.2 gigawatts of capacity expansion from nuclear plant life extensions results in 69,000 GWh of additional nuclear energy in 2010, compared to the reference case.

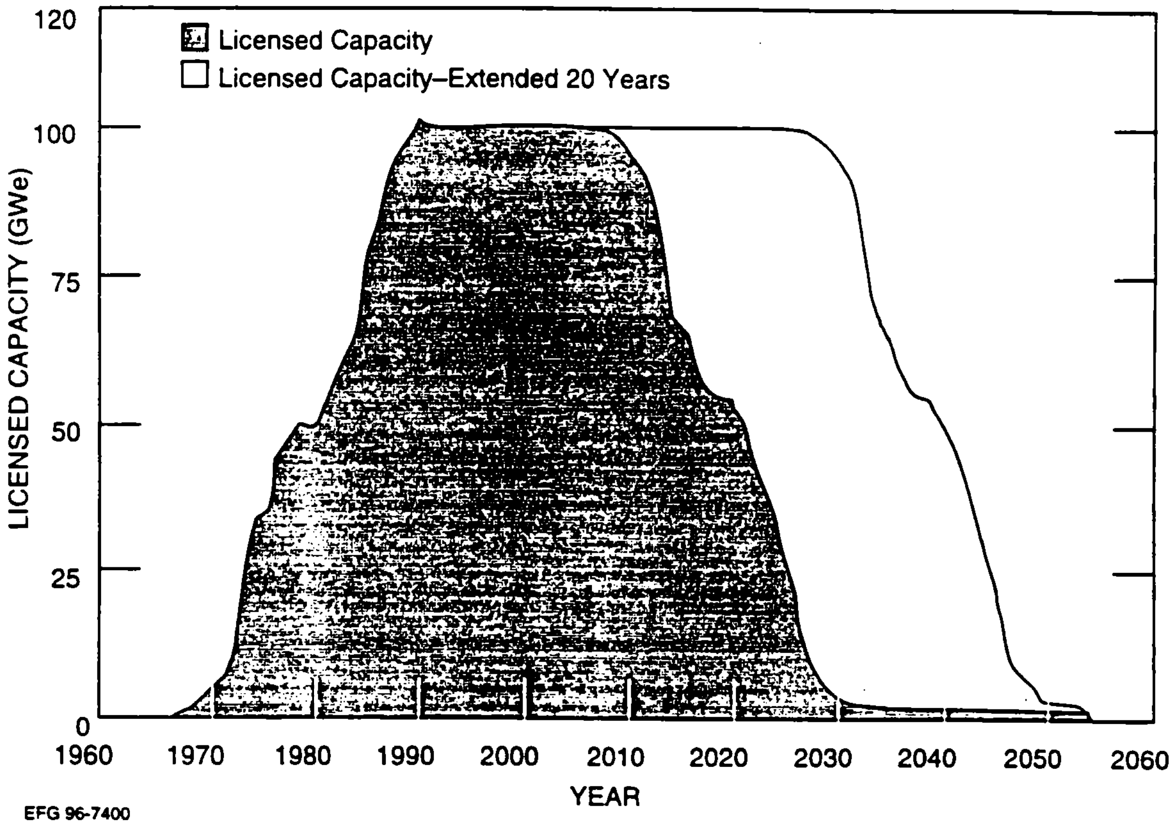
According to EIA's "high nuclear case," 12 Mt of carbon would be offset by this additional carbon-free source of electricity. Using the capacity on the margin in the HE/LC case (with carbon emissions averaging 160 tonnes/GWh), we estimate that the carbon reductions from this additional nuclear resource drop to 11 MtC. A range of 4-7 MtC (from 35-65% of this potential) would appear to be a more realistic forecast for the HE/LC scenario. This range recognizes that it will not be economical or politically feasible to extend the operation of nuclear power plants with licenses that expire by the year 2010.

The AEO97 reference case forecasts that nuclear capacity in the U.S. will decline at an increasing pace after 2010, decreasing from 88.9 gigawatts in 2010 to 62.7 gigawatts in 2015. Thus, with the demand for energy continuing to grow, the impact of nuclear power as a carbon offset declines precipitously over this slightly longer planning horizon. Under the "high nuclear case," the assumed 10-year nuclear plant licensing extensions (subject to the 4 cents/kWh maximum cost) increases nuclear capacity in 2015 from 62.7 gigawatts (in the reference case) to 94.7 gigawatts (in the "high nuclear case"), Thus, the magnitude of carbon offsets offered by this strategy becomes quite significant after 2010.

Figure 7.15 illustrates the accelerated role that nuclear power life extension could have in offsetting carbon emissions after 2010. Only 45 of the nation's 105 nuclear plants have licenses that extend beyond 2020 (Nuclear Regulatory Commission, 1996). An effort to maintain the viability of this capacity could result in a very large contribution to carbon reductions over the next quarter century.

AEO97 does not estimate the cost of its "high nuclear case," although it acknowledges that the physical degradation of some units would have to be reversed. OTA (1991) also notes the potential carbon savings of extending the useful life of all nuclear plants to 45 years, but assumes that this option involves either low costs or saves money. Understanding the effects of aging in order to better manage the aging nuclear infrastructure is an important R&D topic. Pressure vessel embrittlement and the degradation of cables, pumps, and valves can be better managed by advances in materials science and by developing and implementing advanced monitoring technologies. Such technologies are the result of R&D and help maintain the current licensing basis of the nation's nuclear power plants, thereby enabling their operation to extend beyond the initial 40-year licensing period.

Figure 7.15 U.S. Commercial Nuclear Power Reactor Generating Capacity



7.6 ADVANCED COAL TECHNOLOGIES

To test the possible effects on carbon emissions of other advanced fossil-fired electricity generation technologies, we replaced the advanced technologies used by EIA with estimates from DOE's Office of Fossil Energy (see Table 7.6). These estimates changed the construction costs and heat rates for advanced combustion turbines, combined-cycle units, and coal units. ORCED did not select the advanced coal unit with either the EIA or the Fossil Energy estimates of this unit's costs and operating characteristics; in both cases, its initial cost was too high to warrant inclusion in the generation mix. The only significant change to occur was the replacement of the most advanced combustion turbine as specified by EIA with an older combined cycle unit. The net effect of this change on carbon emissions was negligible.

This limited analysis suggests that between now and the year 2010, highly efficient (i.e., a heat rate of about 7000 Btu/kWh) but expensive (i.e., a cost of over $1000/kW) advanced coal units cannot compete economically with either the generation mix that remains from the 1990s or with gas-fired combined-cycle units.

Table 7.6 Base Case Technologies Compared to Advanced Technologies (costs in 1995$)

	Original	Alternative	Original	Alternative
Advanced Gas Combined Cycle				
Year of construction	2005	2005	2009	2010
Capital Cost, $/kW	410	525	410	500
Heat Rate	6284	5688	5817	5538
Fixed O&M, $/kW-yr	27	16	27	16
Variable O&M, ¢/kWh	0.05	0.015	0.05	0.015
Advanced Gas Combustion Turbine				
Year of construction	2002	2005	2008	2010
Capital Cost, $/kW	339	400	374	364
Heat Rate	10873	8699	7793	8533
Fixed O&M, $/kW-yr	11.9	17.6	16.9	17.6
Variable O&M, ¢/kWh	0.010	0.012	0.05	0.012
Advanced Coal				
Year of construction	2006	2005		
Capital Cost, $/kW	1340	1050		
Heat Rate	9600	7064		
Fixed O&M, $/kW-yr	34	26		
Variable O&M, ¢/kWh	0.25	0.2		

7.7 SUMMARY

ɔle 7.7 summarizes the potential reductions in carbon emissions that could occur as the result of the ɔhnology options discussed in this chapter. Each option is intended to reflect roughly the amount that could be achieved under aggressive policies combined with a carbon incentive of approximately $50/tonne. The total carbon reductions from the options shown in Table 7.7 range from 80 to 117 MtC by the year 2010. Additional carbon reductions may result from landfill gas recovery, photovoltaics, geothermal, and solar thermal resources.

The analysis of renewable energy potential over the next quarter century indicates that with a vigorous and sustained program of research, development, and deployment, renewable energy technologies could be providing a greater and rapidly growing contribution to electricity generation by the year 2020. The potential contributions of carbon sequestration, advanced coal technology, and nuclear power were not explored in this report.

Table 7.7 Carbon Reduction Potential of Selected Electricity Supply Technology Options in the HE/LC Scenario with Carbon Permit Price of $50/tonne

	High-Efficiency/Low-Carbon Case (MtC)
Converting coal-based power plants to natural gas	44
Cofiring coal with biomass	16-24
Wind	6-20
Hydropower	3-9
Efficiency Improvements	7-13
Extending the life of existing nuclear plants	4-7
Total	80-117

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EN[illegible]TES

[1] [illegible] approaches include (1) repowering with an advanced coal technology (integrated coal gas[illegible]tion combined cycle (IGCC), or pressurized fluidized bed combustion (PFBC)) or (2) plant per[illegible]nce (efficiency) improvements through various management and technical adjustments. Wi[illegible]h of these "other" repowering options, the carbon emissions reduction potential is not as grea[illegible] with NGCC due to (1) the magnitude of efficiency improvement and (2) the carbon (together wit[illegible]lfur and nitrogen) content of coal versus natural gas.

[2] All [illegible]l-fired power plants greater than 50 MW, and projected to remain in operation, were con[illegible]ed for NGCC repowering: 22.5 gigawatts (GW) of capacity identified by EIA in AEO97 to be une[illegible]ic were deleted, as were 47.5 GW determined to be unneeded due to end-use energy effic[illegible]y improvements (see Section 6). Appendix G-2 discusses the deletion of this capacity from the [illegible]l/gas repowering analysis.

[3] On[illegible]illion Btu (MBtu) is the equivalent of one thousand cubic feet (MCF) of natural gas. One trilli[illegible]bic feet of natural gas is abbreviated as TCF.

[4] Th[illegible]stimate of gas transmission cost may be high, since it may overestimate the amount of inter[illegible] and intrastate pipeline that is needed to serve the repowered capacity. Alternatively, since [illegible] costs are averaged over all candidate plants based on gas volume delivered to the repo[illegible] site, it may approximate the diseconomies of scale that might arise in expanding comp[illegible]sion or building new pipeline to serve only a limited amount of repowered capacity.

[5] A [illegible]tant 1995 gas/coal price differential assumes that (1) end-use energy efficiency has an offse[illegible] effect on increased utility gas consumption and/or (2) extraction/production costs for natur[illegible] gas decline at the same rate as the increase in demand.

[6] The [illegible]/coal price differential of $0.72/MBtu represents the 1995 value as reported by EIA in its Annu[illegible]nergy Outlook (AEO97). It represents a lower bound value, since the differential remains const[illegible] over time (and demand), reflecting no price response by the natural gas industry with incre[illegible] utility fuel demand. The $1.18/MBtu reflects the 2010 gas/coal price differential within AEO[illegible] This differential reflects a real natural gas price increase of $0.40/MBtu ($2.04/MBtu in 1995 [illegible].44/MBtu in 2010) and a 1.9 TCF increase in utility gas demand.

[7] "Par[illegible] Repowering" is equivalent to the "no additional transmission cost" case.

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Accelerating Globalization?
The Economics Effects of Climate Change Policies on U.S. Workers

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Executive Summary

The Framework Convention on Climate Change, which the U.S. and other countries signed in 1992, commits the signatory countries to limit, and ultimately reduce, their emissions of greenhouse gases. These measures were designed to limit the damages which could result from climate changes associated with increasing concentrations of these gases in the world's atmosphere. Most manmade GHGs are generated through the burning of fossil fuels, so reducing their emissions will require limits on energy use. The signatories to the Convention are now engaged in negotiations that could lead to a treaty with binding commitments to reduce GHG emissions at a Conference of the Parties in Kyoto, Japan in December 1997.

This report examines the costs to the U.S. economy of some of the policies that have been proposed to limit GHG emissions. While there have been a number of studies of the costs of these policies, inadequate attention has been given to the effects of greenhouse gas policies on the distribution of income. We analyze a set of possible GHG policies using the DRI/McGraw-Hill model of the economy, and we find that these policies could have significant costs for the economy, especially in the next ten to fifteen years, and that their distributional effects would be even larger than their effects on the overall level of output. Policies designed to stabilize U.S. emissions of greenhouse gases at 1990 levels in 2010 — the least restrictive policies now being discussed for the Kyoto negotiations — could reduce the level of national output by 1.8 to 2% in the short run, relative to the base case of no GHG policies. Because of the increase in real energy prices, consumption would fall even more, from 2.2 to 2.5%, relative to the base-case forecast. If GHG emissions are reduced by 10% in 2010, then the short-run costs increase sharply, to 2.9% of GDP and 3.6% of consumption. The key impacts of GHG policies in the three cases analyzed in this report are summarized in Table A.

The effects of GHG policies on the distribution of income and employment should be considered in the broader context of overall labor market trends. U.S. production workers have experienced a steady erosion in their real wages since at least 1973 (Mishel, *et al* 1997). Wages are eroding for a number of reasons, including declining rates of unionization, falling real values of the minimum wage, deregulation and increased rates of immigration. Rapid growth in foreign trade and investment are also important causes of declining real wages. Unless these issues are considered in the development of GHG policies, those measures will exacerbate the effects of globalization on American workers. Without offsetting measures, these policies can lead to further downward pressure on the wages of the three-quarters of the workforce that does not have a college degree.

The DRI/McGraw-Hill model shows that GHG policies could cut wage growth in half over the next two decades. GHG policies will have a strikingly consistent, negative impact on real wages. These reductions in real wage growth, relative to the base case, will continue for over a decade. Real wages decline in all three scenarios between 2000 and 2006, and by 2020 they are only 3% to 4% higher than they were in 1995 (versus a 9% increase in the base case). This translates into an average growth rate of less than 0.2% per year. With such low rates of wage growth the continued increase in inequality will lead to falling wages for most workers.

In the short run, 1.5 to 2.6 million fewer jobs would be created, and in the long run there will be substantial shifts in employment and population between industries and regions of the country. Even in the long run, after the initial shock of adjusting to higher energy prices is absorbed, total employment would still be lower with GHG policies than without them. In addition, 400,000 to 500,000 high-paying job opportunities in mining, transportation and public utilities would be eliminated (relative to base-case forecasts), while 240,00 to 290,000 jobs would be created in low-wage retail trade sectors. In addition, 180,000 to 340,000 high-wage manufacturing jobs would also be eliminated if GHG emission quotas were allocated to industry (rather than auctioned to raise government revenues).

Coal, in particular, is the most carbon-intensive of all the fossil fuels, so all GHG policies will have a disproportionately large impact on this industry. Coal output is projected to fall by 45 to 50% in 2020, relative to a base case with no restrictions on carbon emissions. This will eliminate 35,000 to 38,000 jobs in this industry by 2020, which is already forecast to lose 36,000 jobs in the base case. GHG policies will double projected job losses in this hard-hit sector. Other individual industries that would be especially hard hit by GHG policies include rubber and plastics footwear, leather footwear and related goods, kitchen products, apparel, toys, and various other mining industries (fertilizers, nonferrous metals and iron and ferroalloy ores).

GHG policies will sharply increase energy prices in the U.S., especially for coal and natural gas, as shown in Table A. As a result of higher energy prices, firms and individuals will increase their investments in new and improved homes, cars and other equipment in order to reduce energy use. As a result, the overall capital stock of the U.S. will increase by 8% to 10% by 2020. The increase in investment will create jobs in some industries, while destroying jobs in others.

The DRI/McGraw-Hill model, like most other macroeconomic models, is not designed to fully capture the effects of greenhouse gas policies on patterns of trade or foreign investment flows. Most models assume that the U.S. will continue to purchase most of its imports from other developed countries, which will also need to limit greenhouse gas emissions. However, higher energy prices will increase the competitiveness of exporters based in unaffected low-wage developing countries, who will capture a growing share of the U.S. market. Consequently, the trade deficit will expand as rising energy prices make imports more attractive and our exports less competitive. Increases in energy prices, and in the trade deficit, will cause the shift of resources out of mining and manufacturing into services and other low-wage sectors of the economy that was noted above. This could amplify labor-market problems that will result from GHG policies.

The model forecasts that the trade deficit, as a share of GDP, will increase by 1.3 to 2.1 percentage points if GHG emissions are reduced to 1990 levels in 2010. Imports would increase by $175 to $240 billion per year. The trade deficit would increase by $149 to $240 billion per year. Deficits of this size would have huge impacts on traded goods, especially manufacturing-sector products. Using input output multipliers from the U.S. Department of Commerce, we have estimated that a gross total of 2 to 4 million fewer jobs will exist or be created in industries producing traded goods, and related inputs because of these increases in the trade deficit, as compared with the base case forecast. Jobs will also be created in some sectors, and as a result, gross job displacement is likely to exceed the net job losses described above.

These trade estimates may even be too low. Multinational firms in developed countries will have additional incentives to shift investment to the developing countries, if those countries do not face limits on their emissions of greenhouse gases. The DRI/McGraw-Hill model does not include the effects of plant closures or investment diversion to countries excluded from the agreement, so it may underestimate the effects that GHG policies will have on the U.S. trade deficit, and on manufacturing output, employment, and wages.

Greenhouse gas policies are likely to apply market-based mechanisms to discourage energy use. These could include a tax on the carbon content of fuels, or a system of permits that are auctioned to the highest bidder. This report considers two systems of permits, rather than a direct carbon tax, in which markets ration energy use. Either system will generate substantial amounts of revenue for either the government, or the holders of private permits. If revenues are collected by the government and used to reduce public borrowing, then sustained losses in consumption will result. If the permits are simply granted to businesses, free of charge, then corporate profits will increase dramatically and labor's share of GDP will decline sharply. The DRI model projects that total before tax corporate profits would increase by over $1 trillion per year in 2020, if the permits are simply granted to business, and the share of profits in GDP will increase by 9.4 to 11.3 percentage points. However, if revenues are collected by the government, then profits will not rise as a share of output, and labor's share will not fall.

This report makes no assessment of the potential benefits of GHG policies, in terms of potential risks or damages that could be avoided, nor does it take a position on the advisability of adopting any further policies to restrict GHG emissions. However, we recommend that if such policies are implemented, two specific, additional measures regarding adjustment assistance and border taxes are needed to limit their disruptive effects on the economy, and on the lives of American workers.

The first concerns the impact of GHG policies on globalization of trade and investment. If two different sets of standards or timetables for emission reductions are established for developed and developing counties, they will create incentives for firms to increase imports and move production and investment out of the U.S., in order to take advantage of lower energy prices and less restrictive emission limits in the developing countries. There are policies available which can reduce the trade and investment distorting effects of GHG policies.

In order to reduce or eliminate the negative effects of GHG policies on U.S. trade and investment, it could even be necessary to establish a border equalization tax policy. This tax would rebate the cost of emission limits on the energy content of exports, and assess an equivalent fee on products imported into the U.S. This kind of policy could eliminate the incentive to import goods and move plants abroad to escape U.S. emission limits. Other policies which could reduce the effects of GHG policies on trade and foreign investment include quotas on energy intensive imports, and safeguard measures to limit import surges. However, each of these measures could conflict with our obligations under the GATT, increasing the difficulty of developing a comprehensive GHG policy package.

The second type of policy that would be needed is a set of measures that would provide substantial assistance to the workers and communities damaged by the creation of greenhouse gas policies. For workers, such a program should involve meaningful retraining opportunities, and several years of income support while involved in those activities. For particularly hard hit sectors and regions, special programs could be required to provide for early retirements, buyouts and to ensure continuation of health and pension benefits. For communities, there are many options including, but not limited to, industrial and R&D policy support.

Worker retraining policies, especially in the trade adjustment area, have established a poor track record, which may raise questions about the wisdom of incorporating such measures into a GHG policy or treaty package. These policies have failed for several reasons. They have historically been poorly funded, not providing sufficient resources for meaningful retraining nor the time and family income needed to sustain it. In addition, commitments have often been dishonored in the past, when funding for adjustment programs was terminated or drastically reduced after the policy had been implemented. For these reasons, a much larger and more dependable commitment of resources would be needed to compensate workers and communities for the costs of GHG policies.

Finally, we conclude by noting three areas of uncertainty. First, there is substantial uncertainty about the pace of global warming and the precise climactic impact of a given volume of CO_2 emissions. Second, this report analyzes the costs, but not the potential benefits of climate change policy, including any possible economic benefits. Third, there are many unknowns about the costs of reducing emissions. The DRI model provides one way to estimate those costs. This model could overstate or understate the costs of reducing GHG emissions. If the energy efficiency of the economy grows more slowly than is expected in the base case, then greater reductions in energy use will be required to meet any given standard, which would dramatically increase the costs of compliance. On the other hand, in the past such modeling exercises have produced estimates that have proved, in retrospect, to significantly overestimate the costs of new pollution controls. However, even if the models discussed in this report overestimate the costs of GHG policies by 50% or more, the actual costs would still be large and significant.

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Introduction

The Framework Convention on Climate Change, which the U.S. and other countries signed in 1992, committed the U.S. and other countries to a voluntary plan to reduce emissions of greenhouse gases. In 1995, at the first Conference of the Parties (COP-I), a document was produced which established a process designed "to elaborate policies and measures" which would "set quantified limitation and reduction objectives within specified time frames, such as 2005, 2010, and 2020" for greenhouse gas (GHG) "emissions by sources and removals by sinks."[1] At COP-II in 1996, the U.S. first endorsed the concept of "legally binding" emission targets. The signatories to the Convention are now engaged in negotiations that could lead to a treaty with binding commitments at the third Conference of the Parties in Kyoto, Japan in December 1997.

There is a high level of uncertainty about the benefits of policies to avoid climate change. In fact, it is precisely because of the existence of this uncertainty about the effects, and the costs, of climate change, that some economists have taken an interest in the theoretical aspects of climate change modeling (see, for example, Nordhaus 1994). Some have found that there are greater incentives to implement policies to reduce GHG emissions than would exist if the costs of climate change were known with certainty.

Because of the uncertainly surrounding the benefits of climate change policy, most analysts have focused on an assessment of the costs of GHG policies.[2] However, little attention has been paid to the distributional implications of climate change policies. This paper examines these issues using a model developed by DRI/McGraw-Hill (1997). The results of this modeling exercise are analyzed and contrasted with a recent administration study of the costs of climate change policies (Interagency Analytic Team 1997). DRI/McGraw-Hill also prepared the most extensively cited model used in the IAT report. We refer here to that earlier effort as the IAT model.

There have been a number of surveys of the cost of climate change policies.[3] We rely on some of these studies in our analysis. This report contributes an analysis of the distribution of the costs of climate change policies across society to the debate. We make no assessment of the potential benefits of GHG policies, in terms of potential risks or damages that could be avoided, nor do we take a position on the advisability of adopting any further policies to restrict GHG emissions. However, we recommend that if such policies are implemented, two specific, additional measures regarding adjustment assistance and border taxes are needed to limit their disruptive effects on the economy, and on the lives of American workers.

We begin by describing the baseline forecasts for the economy (business as usual case) and then review the overall effects of potential GHG policies on output (GDP) and consumption, including a comparison of the DRI/McGraw-Hill (1997) results with those of the IAT. The next section considers the effects of these policies on key sectors of the economy, including employment, wages, profits, and foreign trade. We then examine GHG policy-effects on industries and regions of the economy. The paper concludes with a discussion of policy implications and areas for future research.

The Macroeconomic Impacts of GHG Policies

The model used in this study is the DRI/McGraw-Hill macro-economic model. This is a short-run forecasting model with an input-output-based structure. Some analysts have criticized the use of the DRI model to analyze issues such as GHG policies because of its short-run orientation, arguing that the policies proposed should be designed to reduce energy use and carbon emissions over the next century.[4] However, the policies discussed in IAT (1997) would take effect in the year 2000 and be phased in over 10 years. They would have substantial short-run impacts on economic output, which would exceed the costs identified in the other long-run models used in the IAT report.[5] Therefore, it is appropriate to examine these adjustment costs when considering the distributional effects of GHG policies.

Many models have estimated the costs of stabilizing the emissions of carbon, on a national basis, at 1990 levels by the year 2010. This scenario has become the standard of comparison for modeling of the costs of GHG policies. The IAT chose this scenario as a baseline, and also ran a number of "sensitivity-test" scenarios which varied key assumptions, including a range of targets between 90% and 110% of 1990 level emissions in the year 2010. Most scenarios assume that emissions are held constant after the target is achieved in 2010. The European Union has proposed emission reductions of 15% of 1990 levels by 2010 as a starting point for the the Kyoto-round negotiations. It is also important to point out that ultimate stabilization of atmospheric CO_2 may require further reductions in global emission levels beyond these targets, with attendant increases in the costs of GHG policies.[6] Comparison of cases 1 and 2 suggests that the costs of emissions control increase exponentially. Therefore adjustment costs could continue and expand if future COP meetings results in additional, increasingly restrictive agreements to reduce GHG emissions in the Annex-I countries, as seems likely.

Baseline forecasts

DRI/McGraw-Hill (1997) assumes that real GDP growth will average two percent per year between 2000 and 2010, and 1.5% per year thereafter. GDP growth declines after 2010 because the rate of growth of the labor force declines from about one percent per year between 2000 and 2010 to 0.5% per year thereafter, as the baby boom generation begins to exit the labor force. The energy intensity of the economy is forecast to decline by one percent per year throughout the forecast period. Carbon emissions therefore increase 1.3 percent per year between 2000 and 2010 and 0.8% per year thereafter.

Total carbon emissions in the baseline case are 1,746 million metric tons (MMT) in 2010 and 1,894 MMT in 2020. Actual emissions in 1990 in the U.S. were 1323 MMT, according to DRI/McGraw-Hill (1997).[7] Therefore total emissions in the baseline case grow 32.0% and 43.2%, respectively, in 2010 and 2020 in this model. These are the amounts by which carbon emissions would have to be reduced to stabilize emissions at 1990 levels.[8] Some fuels, such as natural gas and petroleum, emit much less carbon per unit of energy released, so energy use would not have to fall by this amount if fuel switching were to occur (as is assumed in the DRI model).

Policy Scenarios

It is assumed that a system of tradeable carbon emission permits is announced and implemented beginning in 2000. The number of permits in circulation is reduced each year from 2000 to 2010, until the emissions target is achieved. Permits are not traded internationally, but are tradeable within the domestic market, to facilitate adjustment at least possible cost. Three cases are analyzed[9]:

Case 1: **(Grandfathered Permits)**. Allowance are issued to industry at no cost. Emissions are stabilized at 1990 levels in 2010.

Case 2: **(Grandfathered Permits, 90% of '90 Emissions)**. Allowances are issued to industry at no cost. Emissions stabilized at 90% of 1990 levels in 2010.

Case 3: **(Auction, Deficit Reduction)** Allowances auctioned by U.S. Government, no revenue recycling. Emissions stabilized at 1990 levels in 2010.

Carbon prices range from $180 to $200 per ton in 2010 and $270 to $320 per ton 2020 in DRI/McGraw-Hill (1997), as shown in **Table 1**. These prices have very different effects on different types of fuel, as noted above. Gasoline prices increase only 31.5% to 49.2% in 2010, for example ($.41 to $.63/gallon). However, coal prices rise much more rapidly, 450% to 680%, because coal has a much higher carbon content per unit of energy, as noted above. Natural Gas, which is one of the most carbon-efficient fuels, rises substantially more in price than gasoline because fuel switching sharply increases demand, and capacity is slow to respond.

Energy prices in the IAT draft report are compared in the bottom two sections of Table 1. The base case prices are nearly identical in the two studies. However, carbon prices are much lower in the IAT scenarios. There are two reasons for this. First, the IAT model assumes slightly higher baseline improvements in energy efficiency (1.25% vs. 1.0% per year). Therefore, carbon emissions in 2020, for example, are projected to be 1805 MMT in the IAT base case, versus 1894 MMT in DRI/McGraw-Hill (1997), a difference of about 5%. Second, and more importantly, the IAT report apparently assumes larger price and substitution elasticities than DRI/McGraw-Hill (1997). The IAT report has been criticized because "The price elasticities for energy demands need further explanation. Some very rough ...calculations suggest that they may be on the high side.[10]" These comments suggest that the estimates in DRI/McGraw-Hill (1997) may be more reliable than those developed for the IAT.[11]

Effects on Output and Consumption

Figure 1 shows that in the cases considered here, GHG policies could have significant costs for the economy, especially in the next ten to fifteen years. Policies designed to stabilize U.S. emissions of greenhouse gases at 1990 levels in 2010 — the least restrictive policies now being discussed for the Kyoto negotiations — could reduce the level of national output by 1.8 to 2% in the short run. If GHG emissions are reduced by 10% in 2010, then the short-run costs increase sharply, to 2.9% of GDP and 3.6% of consumption. The maximum impact occurs in 2007 in all three scenarios, seven years after the permit system begins to be phased in, but three years before emissions are fully reduced to the target level. Output falls because of the increase in energy prices, shown in Table 1 above, which depresses consumption and investment spending.

Overall inflation rates, shown in **Figure 2,** rise by 0.25 to 1 percentage points during the initial implementation period. By 2020, in the grandfathered permits cases, the cumulative effect of these price effects causes a 7% to 9% increase in the level of the GDP price deflator, relative to the base case, because businesses will pass along the cost of permits to their customers. This increase in the *level* of the GDP deflator is permanent, even though inflation returns to base case levels by 2015.

If permits are auctioned by the government, the policy will have a more depressing effect on output, because the permit fees will cause a sharp, permanent increase in government savings. The effect of the permits is similar to that of a tax increase. Inflation increases in the short run, and then falls below the base case after 2008, reflecting the permanent suppression of demand caused by this policy.

In all three scenarios, investment recovers and is increased as a share of GDP, relative to the base case, as shown in Figure 10, below. Firms and consumers increase their spending on capital goods to increase energy efficiency, effectively substituting capital for energy and accelerating the replacement of the existing capital stock. For example, total purchases of vehicles in 2020 in the three policy scenarios are 200,000 to 500,000 units higher than in the base case. As a result of the increased investment, the available stock of effective non-residential capital increases steadily throughout the forecast period, as shown in Table A, above. By 2020, it is 85 to 10% higher than in the base case.

The increase in investment is effectively financed through a forced increase in national savings in the three policy scenarios. If the permits are simply granted to businesses, free of charge, then business revenues and corporate profits will increase dramatically. Part of these retained earnings will then be available to finance increased investment spending. Savings through the federal budget also increase in all three models, after an initial adjustment period. If permits are grandfathered, then corporate profit tax revenues will increase. If the permits are auctioned by the government, then the revenues will flow directly into the treasury. The model assumes in all cases that the government uses the increased revenues to reduce the deficit or, if there is a surplus, to reduce the stock of outstanding federal debt, increasing the effective rate of government savings.

The increase in national savings and investment that would result from a system of energy permit sales is a key element in all models of the effects of GHG policies. In the long run, the increase in savings and investment causes GDP to be higher in 2020 than in the base case, in all three scenarios, as shown in Figure 1. Furthermore, GDP is growing 0.1 to 0.2 percentage points faster than in the base case in all three scenarios in 2020. Hence, the stimulus to investment provided by GHG policies could slightly increase the underlying rate of growth of the domestic economy, in the long run. However, the assumption that permit sales would increase national savings is highly questionable, for reasons discussed below. In the absence of the stimulus to savings and investment, GDP levels and growth rates would be lower throughout the forecast period.

Figure 3 demonstrates that the increase in real energy prices has a bigger effect on consumption than it does on output. GHG policies have a larger impact on consumption than on GDP for at least two reasons. First, a larger share of output is devoted to investment, for reasons explained above, and thus consumption must decline as a share of national income. Second, the increase in energy prices will force consumers to reduce real purchases of other goods, holding everything else constant (unless overall demand for energy is price elastic, which is not the case in most models).

Consumption losses reach a peak of 2.2 to 3.6 percent in 2007, relative to the base case, as shown in Figure 2. Consumption also recovers, following the GDP path in figure 1. However, overall consumption levels remain about one-half percent below the base case in 2020 in all three scenarios, despite the increased levels of output in that year, reflecting the increase in savings discussed above.

Comparisons with IAT Estimates.

The IAT estimates generated much smaller projections of the losses than would result under similar policy scenarios. For example, **Figure 4** compares predicted changes in total consumption from the base case, assuming grandfathered permits in both the IAT and the DRI/McGraw-Hill (1997) models. The maximum loss in the IAT model, of 1.4%, occurs two years earlier (2006) and is only 55% as large as the maximum loss in the DRI/McGraw-Hill (1997) model of 2.5% of base consumption. The difference between the two forecasts reflects the two key differences in energy forecasts: 1) lower base case energy use in the IAT model; and 2) higher price elasticities in that model.

The Reliability of Critical Assumptions

There are substantial economic and practical reasons to question some of the assumptions underlying both the IAT and the DRI/McGraw-Hill (1997) models. One key assumption concerns they way that revenues from the sale of permits are used in the economy. **Figure 5**, which contrasts two scenarios from the IAT report, illustrates the effects of different ways of handling permit revenues on total consumption in the U.S. If permit revenues are recycled to consumers, rather than being used for deficit reduction, losses to consumers will not fade away over time.[12] In this case, consumption will fall and remain at a lower level throughout the forecast period. Given the political realities of the federal budget processes, it is highly unlikely that permit revenues of the type envisioned here would be used to reduce the budget deficit or the federal debt. For example, forecasts in mid-1997 that the federal budget could achieve a small surplus within the next few years if the economy continues to grow at its current pace have generated a wide range of proposals for using projected revenues for new tax cuts, and/or public spending increases. Therefore, national savings are unlikely to increase as assumed in these models.

Higher levels of federal spending for consumption purposes, for example for defense spending, will not stimulate growth in the way envisioned in the DRI model. Thus the permits are not likely to stimulate as much growth in GDP, nor as rapid a recovery, as is forecast in either the DRI/McGraw-Hill (1997) or IAT (1997). On the other hand, some type of public investment, in areas such a R&D, educational programs and other types of public infrastructure, could have an even larger impact on productivity and economic growth rates than the private investment spending that drives the DRI/McGraw-Hill results. Therefore, the ultimate effects of GHG policies on the economy will be heavily effected by the ways in which the resulting revenues are utilized.

For these reasons it is unlikely that all of the GHG revenue collected by the government would go to deficit reduction. Some federal revenues will probably be returned to consumers (through tax cuts) or otherwise result in new public consumption expenditures. While tax cuts or other expenditures could stimulate the economy, they could not fully offset the depressing effects of GHG policies. Therefore, output is likely to fall with GHG policies, in the long run, in contrast with the case reviewed here.[13] Figure 4 shows that consumption will fall when the permit system is put in place in 2000, recover slightly, and then begin to decline again. The sustained decline is caused by the increase in the cost of carbon permits and energy prices shown in Table 1, above.[14] The increased cost of energy puts an increasing drag on the rate of growth of economic output. This is the most important long-run cost of GHG policies.

The initial decline in consumption shown in Figure 4 is smaller if all the revenues are returned to consumers, perhaps through reductions in income or other labor taxes (such as the social security tax). This "revenue neutral" policy has a less depressing effect on total output and consumption than the grandfathered permits policy. Losses begin to increase in 2015 because of the long-run effects of higher energy prices. The losses and distortion effects shown in Figure 4 would increase with the size of the effective carbon tax. Permit fees as large as those estimated in DRI/McGraw-Hill (1997, $180 to $320 per ton, Table 1 above) would have proportionately larger effects on consumption than the IAT cases (in which permit fees are only $95 per ton in 2010 and $125 in 2020).

One final economic reason for questioning the results of both the IAT and DRI/McGraw-Hill (1997) is that investment may not respond in the way assumed in the models. In each case (except for the auction, 100% to consumer case shown in Figure 4), it is assumed that increases in savings by the business and government sector stimulate a proportionate increase in domestic investment.[15] However, even though corporate retained earnings would rise sharply if permits were grandfathered to existing energy users, there is no guarantee that the resulting excess cash would be invested in the U.S. Investment opportunities elsewhere in the world could be more attractive, particularly if there are parts of the world not subject to GHG policies (as discussed below). In fact, recent empirical research has shown that in the long run, about one-quarter of any given change in savings has flown out of the U.S. in the past. This ratio could change in the future, as well. For these reasons, investment (and therefore GDP and consumption) might not receive the stimulus expected in the IAT and DRI/McGraw-Hill (1997) models even if savings are increased. In fact, increased corporate earnings could accelerate capital flight problems that are discussed below.

On balance, we expect that GHG policies designed to stabilize emissions at 1990 levels will reduce consumption by at least $50 to $100 billion per year, on average, between 2000 and 2020. Losses are likely to continue and grow in the future because the policies will reduce the economy's potential growth rate, because permit revenues are likely to be spent on tax cuts or new public expenditures, and because savings and investment will be diverted to other countries because of the effects of GHG policies on economic incentives. However, the Kyoto negotiations also need to consider the distribution of the benefits and the costs of these policies.

Distributional Effects of GHG Policies

Since 1973, U.S. production workers have experienced a steady decline in their real wages and earnings, as shown in **Figure 6.** After rising steadily at an average rate of $0.14 per hour (in $1982) through 1973, real compensation began to decline steadily thereafter at a rate of $.035 per hour. This decline in production worker incomes contrasts sharply with the continued growth in real hourly earnings of the top twenty percent of the labor force, which has been maintained throughout the 1980s and 1990s. Earnings inequality, the gap between the top and bottom classes of wages earners, has increased sharply as a result. For example, the ratio of the top to the bottom deciles of workers has increased from 3.7 to 4.5 since 1973, an increase of more than 20%.

Wages have been eroding and income inequality has been increasing for a number of reasons, including declining rates of unionization, falling real values of the minimum wage, deregulation and increased rates of immigration. Rapid growth in foreign trade and investment are also important causes of declining real wages (Mishel, Bernstein and Schmitt, 1997). Unless these issues are considered in the development of GHG policies, those measures will exacerbate the effects of globalization on American workers. Recent reports suggest that trade may be responsible for at least 20 to 25% of the increase in U.S. income inequality in this period (Tyson, 1997).[16] With these facts in mind, we turn next to an analysis of the effects of GHG policies on labor and other factors of production, and then examine the effects of GHG policies on trade in some detail.

The effects of GHG policies on employment in DRI/McGraw-Hill (1997) are illustrated in **Figure 7**. As GDP and consumption fall after the permit system is introduced, unemployment (not shown) rises initially and peaks (relative to the base case) in 2006. Overall, unemployment (not shown) is increased by 0.6 to 1.1 percentage points in. To put this in perspective, in the 1990-1991 recession in the U.S., unemployment increased by 2.2 percentage points from its 1989 low of 5.3 percent. Thus, the effects of GHG policies on unemployment are projected be one-quarter to one-half as large as the last U.S. recession.

Job displacement peaks in 2007 or 2008 and persists, as shown in Figure 7, even as excess unemployment is eliminated. Displacement persists, though at lower levels, throughout the forecast period because real wages are depressed by the rise in energy prices (and the overall price level), causing workers to drop out of the labor force. Job losses are especially large in the scenario with the lowest emission targets (grandfathered permits, 90% of '90 emissions), in which energy prices must rise most rapidly.

GHG policies have a strikingly consistent, negative impact on real wages, as shown in **Figure 8.**[17] The rate of growth in real wages is reduced by 0.4 to 0.55 percentage points immediately after the introduction of the permit system in 2000. These reductions in real wage growth, relative to the base case, persist for over a decade. The losses are largest with the most restrictive emission limits (90% of '90 emissions), and least for the case with grandfathered permits and 1990 emission targets. In the latter case there is a small, offsetting, positive effect from the increased ability of corporations to grant wage increases when permits are grandfathered, which increases corporate revenues.

The decade-plus suppression of wage growth rates could cumulatively reduce the growth in the level of real wages by more than 50% between 1995 and 2020, relative to the base case, as shown in **Figure 9.** Real wages decline in all three scenarios between 2000 and 2006, and by 2020 they are only 3% to 4% higher than they were in 1995 (versus a 9% increase in the base case). This translates into an average growth rate of less than 0.2% per year. With such low rates of wage growth the continued increase in inequality will lead to falling wages for most workers. Only the top groups of wage earners are likely to experience any real wage gains over this period.

Impacts on the Business Sector

If GHG policy simply grants permits to business at no cost, then businesses currently using energy will effectively capture the stream of income that is equal to the value of those permits. They can choose to either use the permits themselves, or sell them to other users on the open market. The advantages of this system are that: 1) as the number of permits in circulation is reduced between 2000 and 2010, the lowest cost means of eliminating energy use will be identified by market forces; and 2) the grandfathering of permits will provide some compensation to businesses that will face higher costs of energy because of the implementation of GHG policies.

Under this policy scenario, businesses will capture revenue stream, which will grow in value with the prices of permits, if the permits are given away, as shown in **Figure 10**. Corporate profits (before taxes) are forecast to rise steadily in the base and auction, deficit reduction cases from $500 billion in 1995 to $1.6 trillion in 2020. This reflects both the growth of the capital intensity of the economy (the capital stock is growing faster than in the base case) and an increase in the expected returns to capital, as well as the general growth in real output. If permits are grandfathered, annual corporate profits in 2020 will increase by an additional $1.1 to $1.2 trillion dollars, an increase of about 66%, as a result of the infusion of GHG permit revenues and associate increases in the prices of domestic products.[18]

Investment as a share of GDP will increase in all three GHG scenarios, as shown in **Figure 11.** Higher energy prices will increase the levels of investment in both residential and non-residential goods, including houses, cars and producer durable equipment (production machinery). This will have important side effects, by stimulating the production of capital goods and construction sectors, as shown below. The increase in investment, if it materializes, is the key to generating increased levels of GDP in the DRI/McGraw-Hill forecasts.

A policy induced increase in the level of profits will cause profits to rise sharply as a share of GDP in the two cases where permits are simply given to businesses (grandfathered), as shown in **Figure 12.** This sizeable increase in profits reflects returns on the incremental investment shown in Figure 11, and also returns on the asset value of carbon permits in circulation. In the DRI/McGraw-Hill model, increasing profits have a positive macroeconomic impact, because they provide savings to fund the investment growth. However, rising profits, as a share of national income, also imply a fall in the labor share of income, providing further evidence that production workers will be squeezed by GHG policies. The profit share of output increases by 9.4 and 11.2 percentage points, respectively, in the two cases with grandfathered permits in 2020, with the larger effect occurring with the restrictive target of 90% of '90 emissions. In the base case, profits rise gradually from 7.4% to 15% of GDP. In Scenario's 1 and 2, profits rise to 24.6% to 26.5% of GDP. Such large increases in capital's share of national income would virtually ensure a sizeable increase in the inequality of income distributions in the U.S. .

Effects of GHG Policies on Trade and Investment flows

By 2020, U.S. Imports would rise sharply under GHG policies because higher energy prices would make foreign goods (made with cheaper energy inputs) more attractive, as shown in **Figure 13.** In the short run, as output falls due to the introduction of the permit system, imports will decline slightly. After 2007 they surpass the base case (no GHG policies), and by 2020 they are $175 to $275 billion higher than in the base case. Imports rise most rapidly under the scenario with the most restrictive limits on GHG gases (90% of '90 emissions), because the high costs of carbon permits. The auction, deficit reduction case has the smallest effect on imports, because output is slightly lower than in the case with grandfathered permits (at '90 emission levels).

Real exports, shown in **Figure 14** would fall below base case exports until at least 2013, for all three policy scenarios. Exports recover somewhat thereafter, because of the effects of increased domestic productivity. In particular, in case 2 (permits auctioned, revenues used for deficit reduction) exports are $25 billion higher than in the base case by 2020.

On balance, the increase in imports is considerably larger than the increase of exports, in the long run, in all three cases. Therefore the trade deficit (imports less exports) increases sharply as a share of GDP, as shown in **Figure 15.** The balance improves slightly during the initial period of adjustment to GHG policies, between 2000 and 2010, because of the decline in consumption, but the deficit expands rapidly thereafter. By 2020, the deficit has increased to between 6.0% and 7.5% of GDP, as compared with a 1997 deficit of approximately 2% of GDP. The trade deficit is forecast to grow substantially in the base case, as well. However, the GHG policies would add between $149, $287 and $240 billion to the trade deficit in 2020 in cases 1 through 3, respectively. The trade deficit would increase by 1.3, 2.7 and 2.1 percentage points of GDP in the respective cases.

Deficit increases of this size would have huge impacts on traded goods, especially manufacturing-sector products. We have estimated that $1 billion worth of exports would generate approximately 14,000 domestic jobs, including direct and indirect employment effects, in 1995 (Scott and Lee, 1997). Using this multiplier, the forecast increases in the trade deficit could eliminate a gross total of 2 to 4 million job opportunities in goods producing and related industries. As shown below, the DRI/McGraw-Hill industry projections for 2020 do not reflect employment losses of these magnitudes, because the model assumes that the economy returns to full employment and displaced workers are reabsorbed into other industries by that time.[19] However, if the forecast changes in trade flows are correct, then 2 to 4 million fewer jobs will exist or be created in industries producing traded goods, and related inputs, could occur with GHG policies, as compared with base case employment forecasts. In the long run, increased imports will cause shifts in employment within the manufacturing sector, and between manufacturing and services. As a result, gross job displacement is likely to exceed the net job losses that are discussed below.

If GHG policies do eliminate such a large number of manufacturing jobs, they will have a much larger impact on wages and incomes, especially for non-college educated workers, than is suggested by the DRI/McGraw-Hill macroeconomic model, because wages and incomes are much higher in manufacturing than in other sectors of the economy. Further research is needed to separately estimate the effects of GHG policies on the wages and incomes of blue- and white-collar workers.

There is also a more fundamental set of international trade and investment issues that are not addressed in the DRI model, as suggested by outside reviewers of the IAT, noted above. The DRI model assumes that the share of imports coming from the Annex-I countries (that will impose GHG emission limits) and non-Annex-I countries (which will presumably not be limited, for some time to come) will remain fixed in the base case. However, the structure of trade flows has shifted rapidly in the past 10 years, even without the incentives provided by GHG policies. The share of U.S. imports originating in the developing countries increased from 29.1% in 1978 to 36.4% in 1990, even while the ratio of imports to value added in the manufacturing sector was increasing sharply, from 18.3% to 30.7% (Sachs and Shatz 1994, 10 and 12).

GHG policies will also create incentives to accelerate the pace of globalization and integration of the world economy. Globalization will take at least two forms. First, the share of U.S. imports originating in developing countries will grow, even more rapidly than it has in the past (for example, Mexico and China have experienced some of the most rapid rates of growth in U.S. imports in the 1990s). Second, investment will be diverted from the U.S. to non-Annex I countries, especially Mexico and other countries with large supplies of low-wage, semi-skilled labor. The pool of investment capital available for investing abroad could also be increased if grandfathered permit policies are implemented, as shown above. For the past two decades trade has grown twice as fast as world income, and foreign direct investment has grown four times as fast as income. Globalization is likely to accelerate if GHG policies are implemented that do not limit or otherwise control production shifts designed to escape GHG limits.

Sectoral and Regional Impacts of GHG Policies

Tables 2 and 3 forecast the effects of GHG policies on total and sectoral employment, at a fairly aggregated level in the economy (1- and 2-digit SIC categories of output). Employment changes in 2007 (Table 2) will be dominated by the initial reduction in output, relative to the base case, as noted above. Employment changes will be almost universally negative, and will be spread more or less evenly across the economy. Total losses are greatest when GHG limits are most restrictive (90% of '90 emissions). DRI/McGraw-Hill predicts that a net total of 1.5 to 2.6 million jobs, or about 1.0% to 1.8% of total employment in the base case, will be lost in this first recession. At the high levels of aggregation shown in Table 2, only the energy-related sectors are predicted to experience very large job losses in the short run, including mining (down 11.5% to 15.4%) and petroleum refining (down 2.5% to 7.4%)

In 2020 employment changes are more mixed (Table 3). Total employment declines by 400,000 to 1 million jobs (0.1% to 0.4% of base case employment in 2020), because of the reduction in real wages discussed above. However, employment grows in some sectors (such as other services, retail trade and durable goods) while declining in others (including mining, transportation and non-durables manufacturing). Contract construction employment increases in the two cases with less restrictive limits on carbon emissions because of increased levels of investment. Significant employment losses spread to a much wider range of industries, as the effects of higher energy costs and related changes in other costs are spread throughout the economy. Mining losses rise to 22% to 24% of the base case and petroleum refining employment declines by 17% to 24%. Several industries are forecast to have significant job losses under grandfathered permits, but gains when permits are auctioned and the revenues used to reduce the federal deficit or increase savings, including apparel products, leather products, electrical machinery and miscellaneous manufacturing. These are all sectors that are open to international competition, where production is highly sensitive to wage levels. Nominal wages would be about six percent lower than in the base case by 2020 in the auction, deficit reduction scenario. However, wages are higher than in the base case when permits are grandfathered, which explains why employment impacts differ at the sectoral level in these scenarios.[20]

Employment shifts between industries could contribute to the downward pressure on wages discussed above. **Table 4** reproduces forecasts for employment changes in 2020 from Table 3 for a selected group of the most highly aggregated industries, and also includes information on average production worker wages in these sectors in 1995. This table strikingly illustrates one reason why wages grow so slowly in these scenarios. 400,000 to 500,000 job opportunities in mining, transportation and public utilities, where wages average between $14.22 and $15.32 per hour, would be eliminated (relative to base-case forecasts), while 240,000 to 290,000 jobs would be created in retail trade, which had wages averaging $7.70 per hour in 1995. In addition, 180,000 to 340,000 manufacturing jobs, paying between $11.60 and $12.90 per hour, would also be eliminated if GHG emission quotas were allocated to industry (rather than auctioned to raise government revenues). This process of structural change resulting from GHG policies will contribute to increasing inequality within labor markets in the U.S.

DRI/McGraw Hill also provides detailed forecasts at the 3 digit level for industries, and at the 2 digit level for the 10 census regions of the U.S. **Table 5** reports the industries that are predicted to gain or lose more than 5% of base-case employment in 2020. Losses outweigh gains in Table 4, in several ways. The number of industries experiencing losses of more than 5% of output is more than twice as large as the number with gains of more that 5%. In addition, there are 13 industries that lose more than 10% of output in 2020, including Rubber and Plastics footwear (-56%) coal mining (-45%), other leather goods (-34%) and electric utilities (30%).

However, there are no industries that gain more than 7.1% in total output. These trends reflect the broader tendency for employment to fall in manufacturing, especially durable goods, and rise in services sectors, including education services, retail and wholesale trade and state and local governments, as shown in Tables 3 and 4, above. Other individual industries that would be especially hard hit by GHG policies include kitchen products, apparel, toys, and various other mining industries (fertilizers, nonferrous metals and iron and ferroalloy ores).

Coal mining is one of largest and most heavily affected industries under GHG policies.[21] Coal output is projected to fall by 45 to 50% in 2020, relative to a base case with no restrictions on carbon emissions. The coal industry employed 116,000 workers in 1995. DRI/McGraw-Hill's (1997) base case forecasts that coal industry employment will decline to 80,000 workers in 2020. GHG policies will eliminate another 35,000 to 38,000 jobs in this industry by 2020, reducing total employment to between 42,000 and 45,000 workers. GHG policies will double projected job losses in this hard-hit sector between 1995 and 2020.

The tendency for GHG policies to shift employment from manufacturing to services would be much more pronounced if trade and foreign investment effects were larger, for the reasons noted above. In addition, given the large increase in imports and the trade deficit, shown in Figures 12 and 14 above, DRI may be underestimating the effect of the GHG policies on output at the sectoral level. The shift of employment from manufacturing to services, the growth of imports and the decline in the price competitiveness of U.S. products would all have depressing effects on U.S. wages, for the reasons discussed above.

The shift from manufacturing to services, especially retail trade, is illustrated in **Table 6**, which summarizes forecast changes in population and employment in the 10 census regions of the

U.S. in 2020, under the case 1 assumptions (grandfathered permits, 1990 emission limits). Manufacturing employment (shown in the last column) declines in 9 of 10 regions, rising only in the Pacific Northwest, where it is attracted by the availability of relatively cheap hydro-powered electricity. Retail trade experiences employment gains in 7 of the 9 regions that experience declining manufacturing employment. Mining, especially coal mining, declines sharply in all regions of the country, as noted above. Construction absorbs some of excess labor in regions that are forecast to enjoy stable or rising population levels because of GHG policies. Overall, employment declines in 6 of the regions (more than 1% in the East South Central and West South Central areas), and population declines in 3 of the 10 regions. Changes in energy costs, and the location of employment opportunities drive population shifts. In general, there is a substantial shift of jobs and population to the Pacific Northwest, with the other 7 regions not noted here experiencing small net gains or losses of jobs and employment in Case 1.

Regional and industrial shifts in production and employment will reinforce the tendency of GHG policies to increase income disparities in the U.S. The movement of labor out of high-wage sectors, such as manufacturing and mining, and into low wage sectors, such as retail trade, will tend to increase income inequality across the U.S., as the supply of good jobs for the bottom three-fourths of the labor force is reduced. Regionally, the Pacific Northwest, which already enjoys relatively high standards of living, will experience employment and population gains, while relatively low-income regions such as the East South Central will experience job and populations losses. These changes will tend to increase the disparity which exists in wages and income distributions among these regions, by increasing labor demands in the regions that gain and reducing labor demand in the regions that lose jobs and population.

Policy Implications and Areas for Future Research

To date, the discussion of GHG policies has paid inadequate attention to sectoral, regional and other adjustment policies needed to minimize the negative effects of GHG policies on the distribution of income. Previous research on GHG policies has focused almost exclusively on the identification of costs and benefits at the macroeconomic level of the economy. This analysis adds consideration of equity issues to the debate.

Optimal GHG Control Strategies

As noted above, policy makers are discussing a range of goals for the Kyoto-COP-III meetings and potential agreements. These range from stabilizing emissions in the Annex-I countries at 110% of 1990 levels by 2010 (IAT, 1997), or 2020, to reducing them by up to 20% as soon as 2005.[22] DRI/McGraw-Hill (1997) estimates that stabilizing or reducing emissions at 1990 levels will require an effective carbon permit price of $180 to $192/ton in 2010, and $270 to $281 per ton in 2020 (Table 1, above). Further emission reductions would require substantially higher carbon prices.

Nordhaus (1994, 93-96) has developed a simple simulation model of the costs and benefits of global climate change which identifies optimal emission control rates and the carbon taxes needed to achieve those levels of control (the carbon tax would have essentially the same effect as a carbon permit-fee on energy use and carbon emissions). His model suggests that very small and gradual controls are needed, with carbon taxes of only $5.29 per ton (in 1989 $), rising to $17.75 per ton in 2075.[23] He reviews a number of other, earlier studies which also reached similar conclusions. Fankhauser and Tol (1996) also review a number of recent estimates of the marginal damage of a ton of carbon emissions of $5 to $125 per ton of carbon, "with most estimates in the lower end of this range.” This literature suggests that the emission limits considered in IAT (1997) and DRI/McGraw-Hill (1997) may be too restrictive, in the sense that marginal costs would exceed marginal benefits at the given levels of carbon emission limits.

Measures to Offset the Effects of GHG Policies on Income Distribution

This report makes no assessment of the potential benefits of GHG policies, in terms of potential risks or damages that could be avoided, nor does it take a position on the advisability of adopting any further policies to restrict GHG emissions. However, we recommend that if such policies are implemented, two specific, additional measures are needed to limit their disruptive effects on the economy, and on the lives of American workers.

The first concerns the impact of GHG policies on globalization of trade and investment. If two different sets of standards or timetables for emission reductions are established for developed and developing counties, they will create incentives for firms to increase imports and move production and investment out of the U.S., in order to take advantage of lower energy prices and less restrictive emission limits in the developing countries. There are policies available which can reduce the trade and investment distorting effects of GHG policies.

In order to reduce or eliminate the negative effects of GHG policies on U.S. trade and investment, it could even be necessary to establish a border equalization tax policy. This tax would rebate the cost of emission limits on the energy content of exports, and assess an equivalent fee on products imported into the U.S. This kind of policy could eliminate the incentive to import goods and move plants abroad to escape U.S. emission limits. Other policies which could reduce the effects of GHG policies on trade and foreign investment include quotas on energy intensive imports, and safeguard measures to limit import surges. However, each of these measures could conflict with our obligations under the GATT, increasing the difficulty of developing a comprehensive GHG policy package.

The second type of policy that would be needed is a set of measures that would provide substantial assistance to the workers and communities damaged by the creation of greenhouse gas policies. For workers, such a program should involve meaningful retraining opportunities, and several years of income support while involved in those activities. For particularly hard hit sectors and regions, special programs could be required to provide for early retirements, buyouts and to ensure continuation of health and pension benefits. For communities, there are many options including, but not limited to, industrial and R&D policy support.

Worker retraining policies, especially in the trade adjustment area, have established a poor track record, which may raise questions about the wisdom of incorporating such measures into a GHG policy or treaty package. These policies have failed for several reasons. They have historically been poorly funded, not providing sufficient resources for meaningful retraining nor the time and family income needed to sustain it. In addition, commitments have often been dishonored in the past, when funding for adjustment programs was terminated or drastically reduced after the policy had been implemented. For these reasons, a much larger and more dependable commitment of resources would be needed to compensate workers and communities for the costs of GHG policies.

Limitations and Areas for Future Research

Finally, we conclude by noting three areas of uncertainty. First, there is substantial uncertainty about the pace of global warming and the precise climactic impact of a given volume of CO_2 emissions. Second, this report analyzes the costs, but not the potential benefits of climate change policy, including any possible economic benefits. Third, there are many unknowns about the costs of reducing emissions. The DRI model provides one way to estimate those costs. This model could overstate or understate the costs of reducing GHG emissions. If the energy efficiency of the economy grows more slowly than is expected in the base case, then greater reductions in energy use will be required to meet any given standard, which would dramatically increase the costs of compliance. On the other hand, in the past such modeling exercises have produced estimates that have proved, in retrospect, to significantly overestimate the costs of new pollution controls. However, even if the models discussed in this report overestimate the costs of GHG policies by 50% or more, the actual costs would still be large and significant.

In addition to these general areas of uncertainty, this report has raised a number of specific concerns that require future research. These include the effect of GHG policies on foreign trade and investment, including sectoral details and relationships between the major accounts (merchandise, services, current and capital accounts); and if permits are traded internationally, or joint implementation is allowed (neither of these alternatives was considered in this report), the implications for trade and exchange rates in a general equilibrium context. Another major area of concern is the system for implementing permits, how they will be created and traded, the nature of the property rights involved, and the wealth effects of grandfathering or other forms of distribution to the private sector. There is a related set of issues concerning the distribution of income between labor and capital, and the future rate of return on capital, that GHG policies will also intersect with. Finally, further disclosure, review and debate is needed about the technical assumptions of the models used to analyze GHG policies. This review should include the relevant price and/or substitution elasticities and the potential (and cost) of increasing the energy-efficiency of the domestic economy without GHG policies. Differences in base case level of energy use, during the forecast period, can have a very large impact on the cost of limiting carbon emissions and this issue has not been adequately addressed in the literature.

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Endnotes

1.This section is based on, and the quotes are drawn from Bernstein, Montgomery and Rutherford (1997).

2. Nordhaus (1994), which estimates optimal GHG policies from an explicitly defined welfare model is a notable exception. Other examples include Boyd, Krutilla and Viscusi (1995) and Madisson (1995).

3. See, for example, Hoeller, Dean and Nicolaisen (1991) and Repetto and Austin (1997).

4. See, for example, comments on the IAT draft report in letters released to the House Subcommittee on Energy and Power, as an appendix to Yellen (1997):
Dale Jorgenson and William D. Nordhaus (April 24, 1997) "This model is ... highly inappropriate...extremely sensitive to assumptions about energy prices."The letter also criticized the "use of fixed-coefficient, input-output model." and Raymond J. Kopp (May 15, 1997) stated that the DRI model is "...useful only for the analysis of short-term adjustments, and even here, one should proceed with caution..." because the model is "driven from fixed coefficient input-output tables that can give very distorted views of the adjustment behavior of the economy."

5. The IAT report utilized three models. In addition to the DRI model discussed here, the IAT also developed forecasts for a similar set of policy scenarios using the Markal-Macro and Second Generation Models (SGM). These are simulation-type models that calculate equilibrium output levels, given constraints (such as available energy resources) and a set of initial conditions and assumptions about the structure of the economy. The Markal-Macro and SGM models are not designed to estimate adjustment costs or economic disequilibria that will result from policy changes. Hence the DRI model is better suited to the analysis of displacement issues, while the general class of simulation models are more appropriate for estimating long-run consequences. Note, however, that the IAT was criticized by reviewers for: 1) failing to utilize a full computable general equilibrium model, rather than the Markal-Macro or SGM; and 2) because neither of those models included a well developed foreign trade sector. See comments by Nordhaus and Jorgenson (previously cited), Ray Kopp, John Weyant and Richard Richels, in letters released to the House Subcommittee on Energy and Power, as an appendix to Yellen (1997).

6. See Wiley, T.M.L., R. Richels and J.A. Edmonds 1996.

7. Note that IAT (1997, Table 1) reports that total carbon emissions in 1990 were 1338 MMT, 1.1% more than is reported for 1990 consumption levels in DRI/McGraw-Hill (1997).

8. These target reduction levels are 5% to 8% larger than those required in IAT (1997). The difference is explained by the combination in the IAT report of more rapid declines in the energy intensity of the economy (1.25 percent per year vs. 1.0 percent per year), and the slightly higher baseline level of carbon emissions. The efficiency assumption is the most important difference, by far, between the two baseline cases.

9. A fourth case and a new base case are also analyzed in DRI/McGraw-Hill (1997). These cases assume that the energy intensity of the domestic economy in the "heroic base case" improves at 1.75% per year. This corresponds to a similar scenario in the IAT report. Results parallel those of the cases discussed below. The scenario in case 4 is otherwise identical to case 1 (grand fathered permits). Case 4 and its comparable base case are not analyzed here because the "heroic base case" scenario is highly unlikely to occur.

10. Comments on the IAT draft report released to the House Subcommittee on Energy and Power, as an appendix to Yellen (1997) in letter from Richard Richels, May 30, 1997. See also letter from Larry Goulder, June 2, 1997, "The report seems consistently to employ assumptions and policy scenarios that contribute to low costs of emissions reductions."

11. This view is also supported by Ray Kopp, in a letter of May 30, 1997, who noted that "All of the departures from AEO97 used in the draft report serve to decreased carbon emissions [in the base case] and therefore make attainment of a 1990 stabilization less costly." (Letter released to the House Subcommittee on Energy and Power, as an appendix to Yellen, 1997).

12. Figure 4 is derived from two of the scenarios shown in Figure 16 (p. 28) of the IAT draft report.

13. If public investment were to be increased using GHG revenues, then output, consumption and other segments of the economy could achieve higher levels in the long run than in the cases considered here. However, increases in public investment would appear less likely to obtain than general or targeted tax cuts, in the present political environment in the U.S.

14. Bovenberg and de Mooij (1994) have shown that, in theory, revenue raising environmental taxes can lower economic output because they "exacerbate, rather than alleviate, preexisting tax distortions." Goulder (1995) develops a general equilibrium model which shows that the problem with the carbon tax is its "focus on intermediate inputs and its relatively narrow base in comparison with income taxes." In principle, raising the cost or limiting the supply of energy inputs will change the shape and position of the production possibility frontier, generally reducing the amount of output that can be generated with any given set of other inputs.

15. For example, comparing Case 1 and the Base Case, the increase in investment is about 90% as large as the increase in total national savings.

16. Mishel, Bernstein, and Schmitt (1997, 195) estimate that trade could be responsible for more than 30% of the increase in income inequality in the U.S. between 1979 and 1989.

17. The effects on real wages are estimated by dividing the employment cost index by the consumer price index series in DRI-McGraw-Hill (1997, 20 and exhibit 15). The base case value for this series is then contrasted with each of the forecasts to determine the change in the real value of compensation. Note that DRI-McGraw Hill draws a sharp contrast between changes in the nominal wage series for case 3 (permit auctions) which decline sharply, and the other policy cases, where nominal wages increase because of increases in corporate revenues and hence the

ability to pay. However, the variation in these results is eliminated when real wage series (and the corresponding differences of consumer prices in each case) are considered.

18. This increase in before-tax corporate profits appears to primarily reflects an increase in the implicit rate of return on capital. The cumulative increase in fixed nonresidential capital between 2000 and 2020 in the three cases analyzed here is between $1.0 and $1.4 trillion, roughly equivalent to the increase in annual corporate profits by 2020. Therefore most of the increase in profits would appear to reflect higher returns on existing capital stock. This implicit forecast of increased returns is unrealistic, unless the world-wide corporate rate return on invested capital rises sharply because of GHG policies. However, an alternative view might treat the incremental profits as the returns on the imputed capital value of carbon emission permits. This view suggests that grandfathering of permits will not only transfer revenues to permit holders, but also new assets with a significant capital value. The implicit rate of return of capital, and wealth transfers associated with the permits, are important issues for future research.

19.Note that the DRI/McGraw-Hill (1997) forecasts for the three scenarios contain puzzling and potentially contradictory results. The Merchandise trade balance worsens by less than $100 billion in each case, although the calculated trade balances (including services) decline much more sharply, as indicated in the text. It is unlikely that services trade can or will account for these differences. In addition, the current account balance *improves* by $87 to $175 billion in the three GHG scenarios, presumably because of the increase in national savings. However, improvements of this magnitude in the current account are unlikely unless they are mirrored in changes in the trade balances, which dominate current account transactions.

20. Exchange rates are essentially unchanged in the DRI/McGraw-Hill (1997) forecasts, so changes in nominal wages and prices directly effect competitiveness. The rigidity of exchange rates in these forecasts is a potential source of error.

21. There is a greater percentage drop in employment in rubber and plastic footwear under GHG policies, as shown in Table 4. However, output in this industry was less than $1 billion in 1995, as compared with coal industry output of over $28 billion in that year.

22. Association of Small Island States, 1995, "Draft Protocol Submitted to the United Nations Framework Convention on Climate Change," as referenced in Repetto and Austin (1997, 1).

23. Nordhaus and Yang (1996) develop a regional bargaining model which generates slightly higher optimal permit prices of roughly $30 per ton of carbon in 2090, versus $21 in the DICE model developed in Nordhaus (1994).

Table A
Costs of Greenhouse Gas Policies
Summary of Key Impacts

factor/year:	Case 1 Grandfathered Permits	Case 2 Grandfathered Permits, 90% of emissions	Case 3 Permits Auctioned
Change in GDP			
2007	-2.0%	-2.9%	-1.8%
2020	0.2%	0.0%	0.5%
Change in Consumption			
2007	-2.5%	-3.6%	-2.2%
2020	-0.3%	-0.7%	-0.2%
Change in Total Employment			
2007	(1,800,000)	(2,600,000)	(1,500,000)
2020	(600,000)	(500,000)	(100,000)
Change in Real Wages, Relative to Base Case			
2007	-3.0%	-4.3%	-3.7%
2020	-4.4%	-5.5%	-5.2%
Change in the Profit Share of GDP			
2007	3.3%	4.6%	-0.1%
2020	9.4%	11.3%	-0.4%
Change in the Effective Non-Residential Capital Stock			
2007	0.3%	0.3%	-0.1%
2020	8.2%	10.4%	8.2%
Change in Gasoline Prices			
2010	33.1%	49.2%	31.5%
2020	43.1%	50.0%	43.1%
Change in Natural Gas Prices			
2010	129.6%	183.0%	124.8%
2020	157.8%	179.1%	159.2%
Change Coal Prices			
2010	482.2%	679.4%	451.4%
2020	760.6%	760.6%	729.3%

Sources: EPI analysis of DRI (1997)

Table 1
Energy Price Comparisons

	2010	2020
DRI/McGraw-Hill Base Case		
Implicit Price of Carbon ($1995)	$0.00	$0.00
Gasoline-Retail ($/gallon)	$1.30	$1.44
Coal-Electric Utility ($/mmBtu)	$1.07	$0.99
Natural Gas-Utility ($/mmBtu)	$2.30	$2.77
Electricity-Weighted Average (cents/	$4.90	$4.95
DRI Case 1-- Grandfathered Permits		
Implicit Price of Carbon ($1995)	$192.00	$281.00
Gasoline-Retail ($/gallon)	$1.73	$2.06
Coal-Electric Utility ($/mmBtu)	$6.23	$8.52
Natural Gas-Utility ($/mmBtu)	$5.28	$7.14
Electricity-Weighted Average (cents/	$8.13	$9.58
Percentage Changes from Base:		
Gasoline	33.1%	43.1%
Coal	482.2%	760.6%
Natural Gas	129.6%	157.8%
Electricity	65.9%	93.5%
DRI Case 2-- Grandfathered Permits, 90% of '90 Emissions		
Implicit Price of Carbon ($1995)	$270.00	$320.00
Gasoline-Retail ($/gallon)	$1.94	$2.16
Coal-Electric Utility ($/mmBtu)	$8.34	$8.52
Natural Gas-Utility ($/mmBtu)	$6.51	$7.73
Electricity-Weighted Average (cents/	$9.29	$10.51
Percentage Changes from Base:		
Gasoline	49.2%	50.0%
Coal	679.4%	760.6%
Natural Gas	183.0%	179.1%
Electricity	89.6%	112.3%
DRI Case 3-- Permits Auctioned		
Implicit Price of Carbon ($1995)	180	270
Gasoline-Retail ($/gallon)	$1.71	$2.06
Coal-Electric Utility ($/mmBtu)	$5.90	$8.21
Natural Gas-Utility ($/mmBtu)	$5.17	$7.18
Electricity-Weighted Average (cents/	$8.00	$9.47
Percentage Changes from Base:		
Gasoline	31.5%	43.1%
Coal	451.4%	729.3%
Natural Gas	124.8%	159.2%
Electricity	63.3%	91.3%
Administration-IAT Draft of May 30, 1997		
(1990 Level Case, No International Trading, Permits Auction		
Implicit Price of Carbon ($1995)	95	125
Gasoline-Retail ($/gallon)*	$1.56	$1.73
Percentage Change in Gasoline Pri	19.8%	19.8%
Comparison, DRI (1997) vs. IAT Estimates:		
Implicit Price of Carbon ($1995)	189%	216%
Percentage Change in Gasoline-Ret	160%	218%

*Estimated, assuming ~26 cents gallon of refined petroleum product (IA
Note that IAT Draft assumes slightly lower gasoline prices in its base

Source: EPI analysis of DRI (1997)

Table 2
Employment Change by Industry in 2007
Relative to Base Case

	Grandfathered Permits		Grandfathered Permits, 90% of '90 Emissions		Auction, Deficit Reduction	
	Percent Change	Jobs Lost (thousands)	Percent Change	Jobs Lost (thousands)	Percent Change	Jobs Lost (thousands)
Civilian Employment - HH Survey	-1.3%	(1,800)	-1.8%	(2,600)	-1.0%	(1,500)
Nonagricultural Establishments	-1.3%	(1,800)	-2.0%	(2,700)	-1.2%	(1,600)
Contract Construction	-1.6%	(100)	-2.8%	(170)	-1.3%	(80)
Finance, Insurance & Real Estate	-1.2%	(90)	-1.4%	(110)	-0.3%	(20)
Mining	-13.5%	(70)	-15.4%	(80)	-11.5%	(60)
Transportation and Public Utilities	-2.5%	(170)	-4.2%	(280)	-2.8%	(190)
Total Services	-1.3%	(570)	-2.0%	(880)	-1.0%	(450)
Health Services	-1.3%	(160)	-2.0%	(240)	-1.3%	(150)
Education Services	-0.9%	(20)	-1.3%	(30)	-0.4%	(10)
Other Services	-1.3%	(390)	-2.0%	(610)	-1.0%	(290)
Retail Trade	-1.2%	(290)	-1.9%	(480)	-0.9%	(220)
Wholesale Trade	-0.6%	(50)	-1.3%	(100)	-0.5%	(40)
Federal Government	0.0%	0	0.0%	0	0.0%	0
State and Local Governments	-1.2%	(240)	-1.7%	(340)	-2.3%	(450)
Manufacturing	-1.0%	(180)	-1.2%	(210)	-0.2%	(30)
Nondurables Manufacturing	-1.5%	(110)	-1.7%	(130)	-0.4%	(30)
Food and Products	-0.9%	(15)	-1.2%	(19)	-0.4%	(7)
Tobacco Products	0.0%	0	0.0%	0	0.0%	0
Textiles and Products	-1.8%	(11)	-1.8%	(11)	-0.2%	(1)
Apparel and Products	-3.2%	(23)	-2.5%	(18)	-0.3%	(2)
Paper and Products	-1.2%	(8)	-1.6%	(11)	-0.4%	[illegible]
Printing and Publishing	-1.1%	(18)	-1.3%	(22)	-0.4%	[illegible]
Chemicals and Products	-1.3%	(13)	-2.0%	(20)	-0.5%	(5)
Petroleum Products	-4.1%	(5)	-7.4%	(9)	-2.5%	(3)
Rubber and Plastics Products	-1.2%	(12)	-1.4%	(15)	-0.3%	(3)
Leather and Products	-6.0%	(4)	-4.5%	(3)	0.0%	0
Durables Manufacturing	-0.7%	(70)	-0.9%	(90)	0.0%	0
Lumber and Wood Products	-1.3%	(10)	-1.6%	(12)	0.0%	0
Furniture and Fixtures	-0.8%	(4)	-0.8%	(4)	0.0%	0
Stone, Clay, and Glass	-1.4%	(7)	-2.0%	(10)	-0.4%	(2)
Primary Metal Industries	-1.4%	(9)	-2.0%	(13)	-0.5%	(3)
Fabricated Metal Products	-0.9%	(13)	-1.1%	(16)	-0.1%	(2)
Nonelectrical Machinery	-0.2%	(3)	-0.2%	(4)	-0.1%	(2)
Electrical Machinery	-0.8%	(13)	-0.9%	(14)	0.2%	3
Transportation Equipment	-0.1%	(2)	-0.1%	(2)	0.1%	2
Instruments and Parts	-0.1%	(1)	-0.3%	(2)	0.1%	1
Miscellaneous Manufacturing	-2.3%	(9)	-2.3%	(9)	-0.5%	(2)

Source: EPI analysis of DRI (1997)

Table 3
Employment Change by Industry in 2020
Relative to Base Case

	Grandfathered Permits		Grandfathered Permits, 90% of '90 Emissions		Auction, Deficit Reduction	
	Percent Change	Jobs Lost (thousands)	Percent Change	Jobs Lost (thousands)	Percent Change	Jobs Lost (thousands)
Civilian Employment - HH Survey	-0.4%	(600)	-0.3%	(500)	-0.1%	(100)
Nonagricultural Establishments	-0.3%	(500)	-0.3%	(500)	-0.1%	(100)
Contract Construction	0.3%	20	-0.2%	(10)	1.5%	90
Finance, Insurance & Real Estate	-0.5%	(40)	-0.4%	(30)	0.7%	60
Mining	-22.2%	(100)	-24.4%	(110)	-22.2%	(100)
Transportation and Public Utilities	-5.6%	(350)	-6.4%	(400)	-5.0%	(310)
Total Services	-0.9%	(490)	-0.9%	(480)	-0.5%	(280)
Health Services	-2.2%	(320)	-2.3%	(330)	-2.0%	(290)
Education Services	0.9%	20	1.4%	30	1.4%	30
Other Services	-0.5%	(180)	-0.5%	(190)	-0.1%	(20)
Retail Trade	0.9%	240	1.1%	290	0.9%	250
Wholesale Trade	0.1%	10	-0.2%	(20)	0.8%	70
Federal Government	0.0%	0	0.0%	0	0.0%	0
State and Local Governments	1.7%	390	2.3%	520	-0.8%	(180)
Manufacturing	-1.1%	(170)	-2.1%	(330)	1.5%	240
Nondurables Manufacturing	-2.5%	(180)	-3.1%	(220)	0.4%	30
Food and Products	-1.3%	(20)	-1.1%	(17)	-1.1%	(17)
Tobacco Products	0.0%	0	0.0%	0	9.1%	1
Textiles and Products	-2.5%	(12)	-2.5%	(12)	3.3%	16
Apparel and Products	-8.8%	(49)	-9.1%	(51)	3.9%	22
Paper and Products	-1.3%	(8)	-2.4%	(15)	0.0%	0
Printing and Publishing	-1.0%	(17)	-0.9%	(15)	0.4%	7
Chemicals and Products	-2.4%	(24)	-4.9%	(48)	0.1%	1
Petroleum Products	-20.0%	(20)	-24.0%	(24)	-17.0%	(17)
Rubber and Plastics Products	-1.7%	(20)	-2.6%	(30)	0.9%	10
Leather and Products	-21.6%	(11)	-27.5%	(14)	5.9%	3
Durables Manufacturing	0.0%	0	-1.2%	(110)	2.4%	210
Lumber and Wood Products	0.1%	1	-0.3%	(2)	3.8%	27
Furniture and Fixtures	1.5%	6	1.0%	4	5.9%	24
Stone, Clay, and Glass	-0.9%	(4)	-2.4%	(11)	1.5%	7
Primary Metal Industries	-2.8%	(15)	-5.9%	(32)	-0.2%	(1)
Fabricated Metal Products	-0.2%	(3)	-1.0%	(15)	2.3%	33
Nonelectrical Machinery	2.5%	38	2.2%	33	0.8%	12
Electrical Machinery	-4.0%	(51)	-7.0%	(90)	1.9%	25
Transportation Equipment	3.1%	45	2.3%	34	3.7%	55
Instruments and Parts	1.3%	8	-0.5%	(3)	3.6%	22
Miscellaneous Manufacturing	-5.7%	(22)	-7.3%	(28)	2.1%	8

Source: EPI analysis of DRI (1997)

Table 4
Employment by Industry in 2020
Change from the Base Case

	Case 1 Grandfathered Permits		Case 2 Grandfathered Permits, 90% of '90 Emissions		Case 3 Auction, Deficit Reduction Grandfathered Permits		Average Hourly Earnings 1995*
	percent	thousands	percent	thousands	percent	thousands	
Total Civilian Employment	-0.4%	(606.3)	-0.3%	(491.0)	-0.1%	(127.3)	
Nonagricultural Establishments	-0.3%	(498.8)	-0.4%	(579.0)	-0.1%	(153.5)	$11.46
Contract Construction	0.4%	23.3	-0.2%	(10.1)	1.4%	88.5	$15.04
Finance, Insurance and Real Estate	-0.5%	(39.6)	-0.3%	(26.9)	0.8%	64.9	$12.33
Mining	-23.4%	(106.2)	-17.5%	(116.6)	-22.0%	(99.8)	$15.32
Transportation and Public Utilities	-5.6%	(346.6)	-6.4%	(395.9)	-4.9%	(305.9)	$14.22
Services	-0.9%	(490.5)	-0.9%	(488.8)	-0.5%	(282.5)	$11.41
Retail Trade	0.9%	236.5	1.1%	287.5	0.9%	248.6	$7.70
Wholesale Trade	0.2%	17.8	-0.2%	(18.6)	0.9%	75.2	$12.40
Federal Government	0.0%	0.0	0.0%	0.0	0.0%	0.0	n.a
State and Local Government	1.7%	394.7	2.3%	527.6	-0.8%	(176.8)	n.a
Nondurables Manufacturing	-2.5%	(181.4)	-3.2%	(226.2)	0.3%	24.3	$11.60
Durables Manufacturing	0.0%	2.2	-1.3%	(110.9)	2.4%	210.1	$12.90

*"Employment and Earnings", March 1996. Average hourly earnings for production and non-supervisory workers in the private sector, from the establishment survey.

Source: EPI analysis of DRI (1997)

Table 5
Industrial Winners and Losers
Sectors Experiencing Gains or Losses of More than 5% in Output in 2020 with Grandfathered Permits

Losses Exceeding 5%	Change in Output from Base Case 2010	2020
086 Rubber & Plastics Footwear	-54.3%	-55.9%
012 Coal Mining	-45.9%	-45.3%
091 Other Leather Goods	-24.0%	-33.7%
207 Electric Utilities	-19.7%	-29.6%
014 Natural Gas	-13.7%	-28.1%
208 Gas Utilities	-13.4%	-27.3%
160 Household Audio & Video Equip.	-12.5%	-22.4%
081 Petroleum Refining Ex. Fuel Oil	-11.7%	-19.0%
090 Leather Footwear	-15.9%	-16.0%
203 Pipelines, Ex N. Gas	-10.1%	-13.7%
082 Fuel Oil	-11.3%	-13.0%
096 Kitchen Pottery Products	-11.9%	-12.5%
190 Watches & Clocks	-8.9%	-12.4%
013 Crude Petroleum	-5.2%	-8.7%
042 Apparel From Purchased Mat'l	-8.8%	-8.3%
195 Toys & Sporting Goods	-7.2%	-7.6%
016 Chemical & Fertilizer Mining	-5.7%	-6.6%
089 Leather Tanning & Finishing	-7.7%	-6.5%
011 Misc. Nonferrous Ores	-4.4%	-6.4%
010 Copper Ore Mining	-5.0%	-6.0%
108 Nonferrous Metals NEC	-4.3%	-5.8%
009 Iron & Ferroalloy Ores	-6.0%	-5.6%
083 Lubricating Oils and Greases	-5.4%	-5.0%
Gains Exceeding 5%		
017 New Construction	0.0%	5.0%
130 Elevators & Mat'ls Handling Eq.	1.8%	5.2%
174 Motor Vehicles	1.5%	5.4%
146 Other Service Industry Machinery	2.1%	5.4%
141 Packaging Machinery	2.7%	5.8%
052 Partitions & Fixtures	1.9%	6.0%
127 Lawn & Garden Equipment	2.4%	6.1%
148 Computer Peripheral Equipment	2.4%	6.6%
172 Truck & Bus Bodies	3.2%	7.0%
173 Truck Trailers	3.6%	7.1%

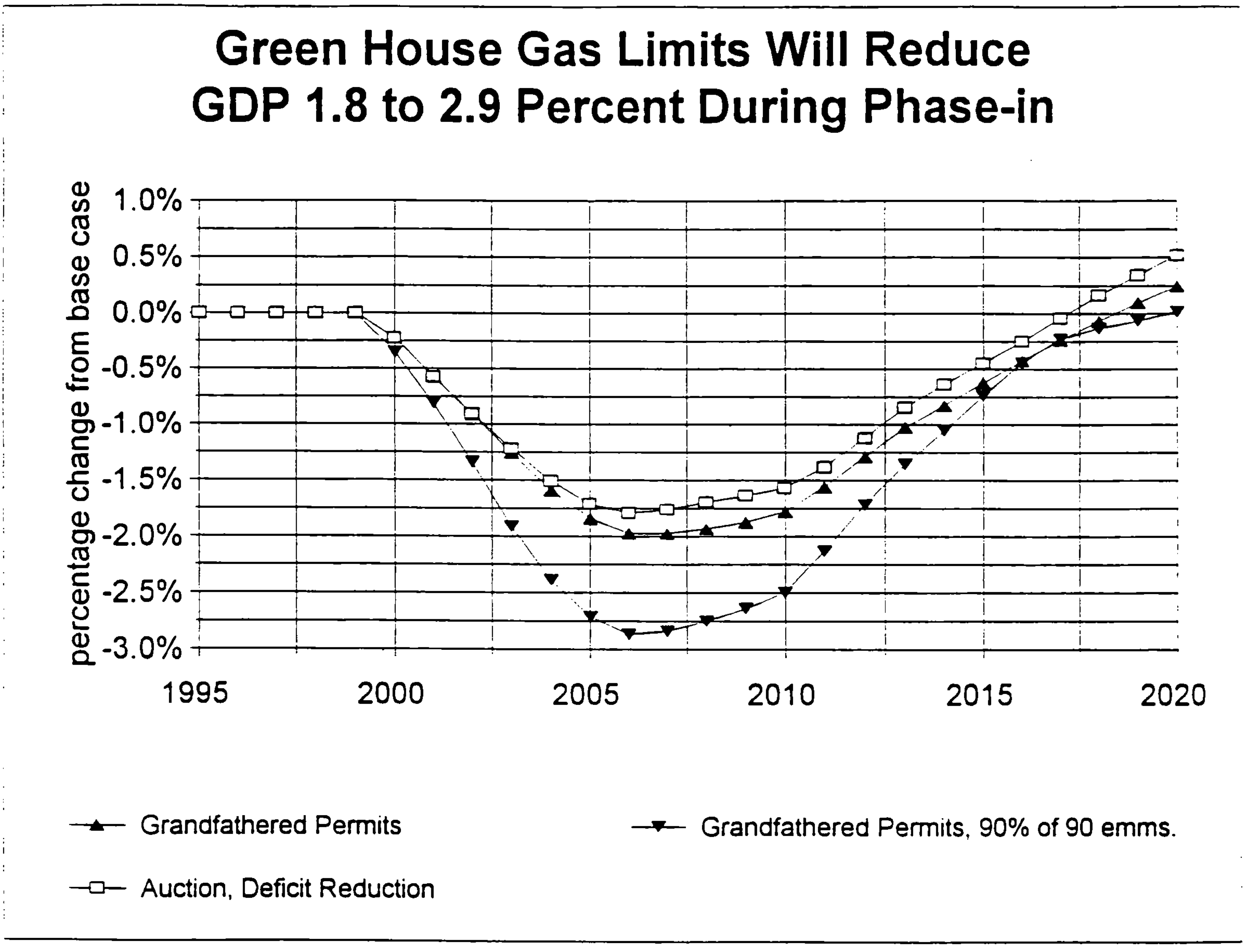
Source: EPI analysis of DRI (1997)

Table 6
Regional Gains and Losses
Changes in Population and Employment in 2020
(Grandfathered Permits, Percent Change from Base)

Region	Resident Population	Civilian Employment (HH Survey)	Contract Construction	Mining total	Mining Coal	Total Services	Retail Trade	Manufacturing
New England	0.3%	0.1%	0.4%	-3.7%	-51.2%	-3.0%	1.1%	-1.7%
Middle Atlantic	0.0%	-0.3%	6.7%	-23.3%	-41.5%	-0.8%	0.7%	-1.9%
South Atlantic	-0.3%	-0.8%	-0.5%	-28.3%	-40.3%	-1.3%	0.3%	-1.6%
East North Central	0.3%	-0.1%	0.5%	-19.8%	-39.5%	-0.7%	1.2%	-0.5%
East South Central	-1.1%	-2.0%	-1.4%	-33.1%	-39.8%	-3.5%	-0.5%	-2.1%
West North Central	0.5%	0.2%	1.5%	-10.1%	-43.5%	-0.9%	2.1%	-0.4%
West South Central	-0.6%	-1.1%	-0.9%	-20.3%	-65.5%	-1.8%	-0.3%	-1.1%
Pacific Northwest	1.7%	1.6%	1.4%	-20.9%	-47.5%	1.2%	4.5%	1.5%
Pacific Southwest	0.1%	-0.3%	-0.2%	-14.3%	-36.1%	-0.5%	1.0%	-1.5%

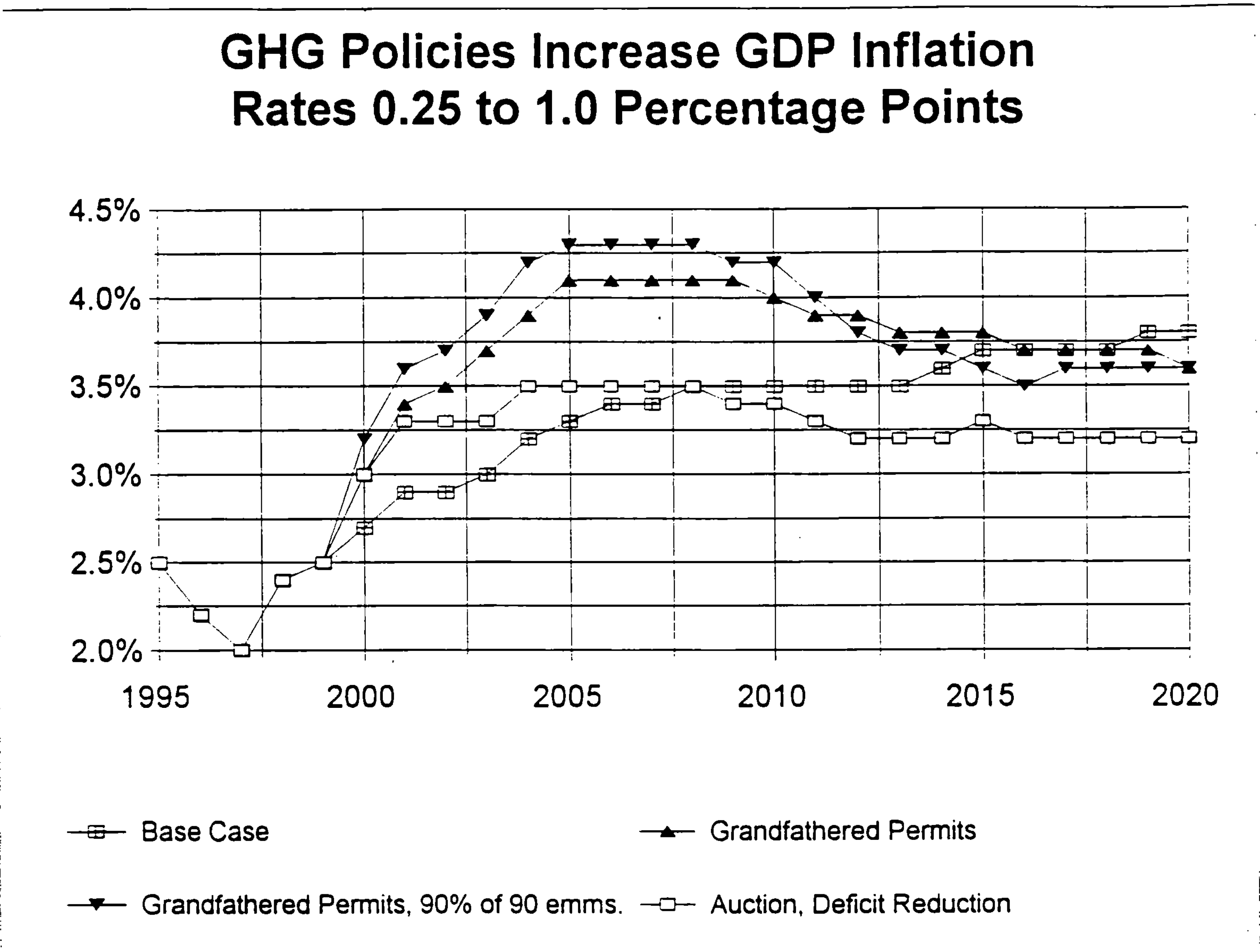
Source: EPI analysis of DRI (1997)

Figure 1



Source: EPI analysis of DRI (1997)

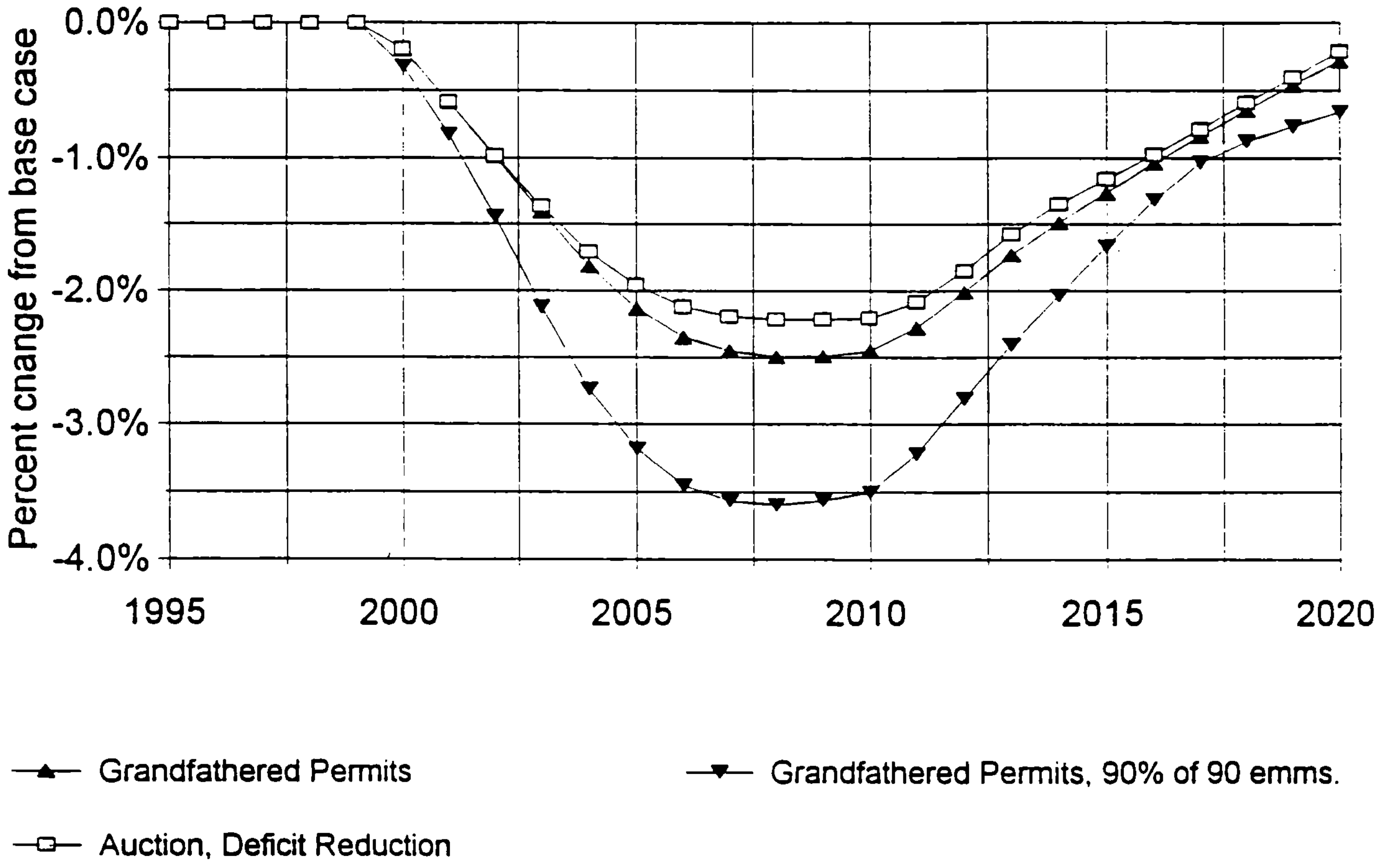
Figure 2



Source: EPI analysis of DRI (1997)

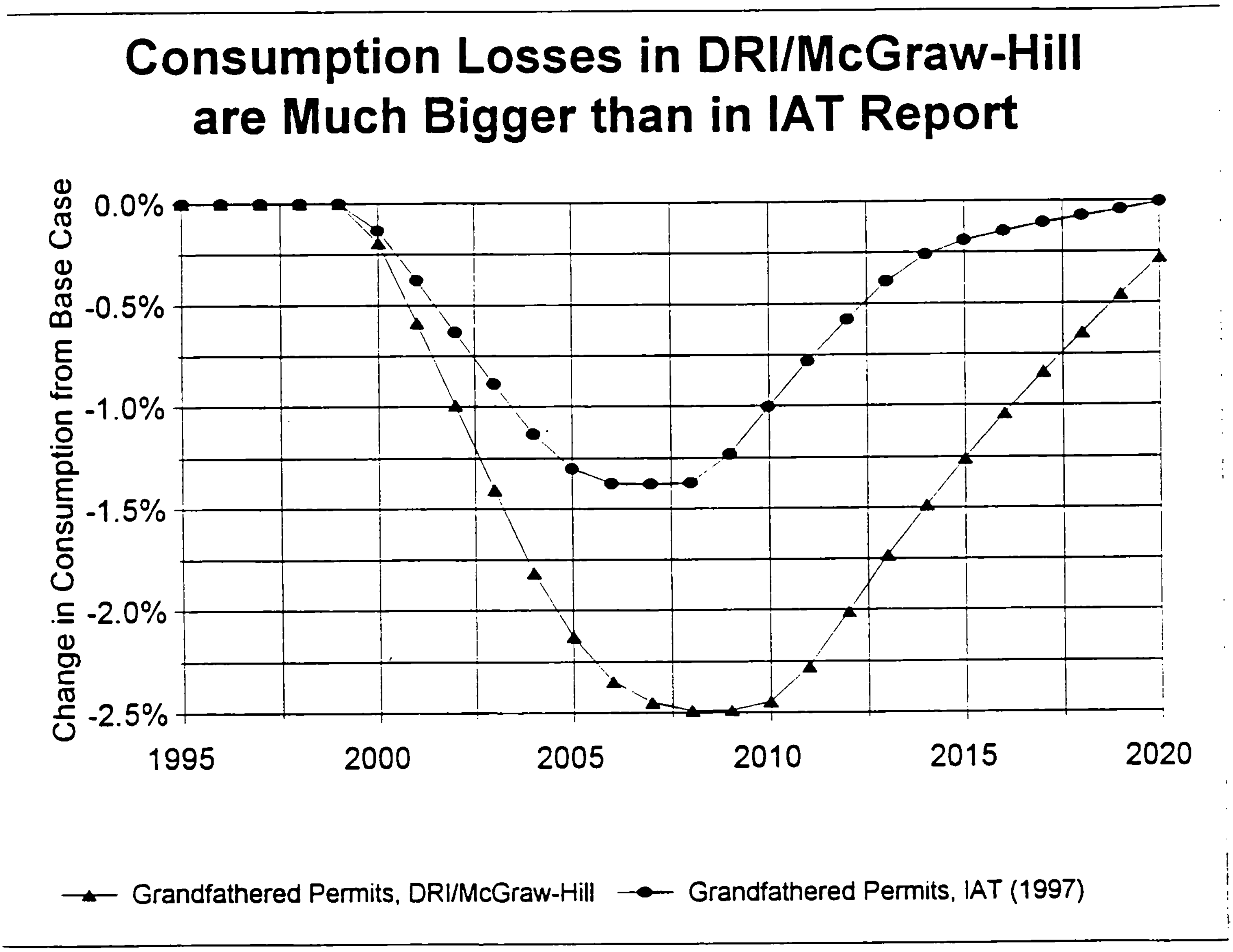
Figure 3

GHG Policies Will Reduce Consumption by 2.2 to 3.6 Percent During Phase-in



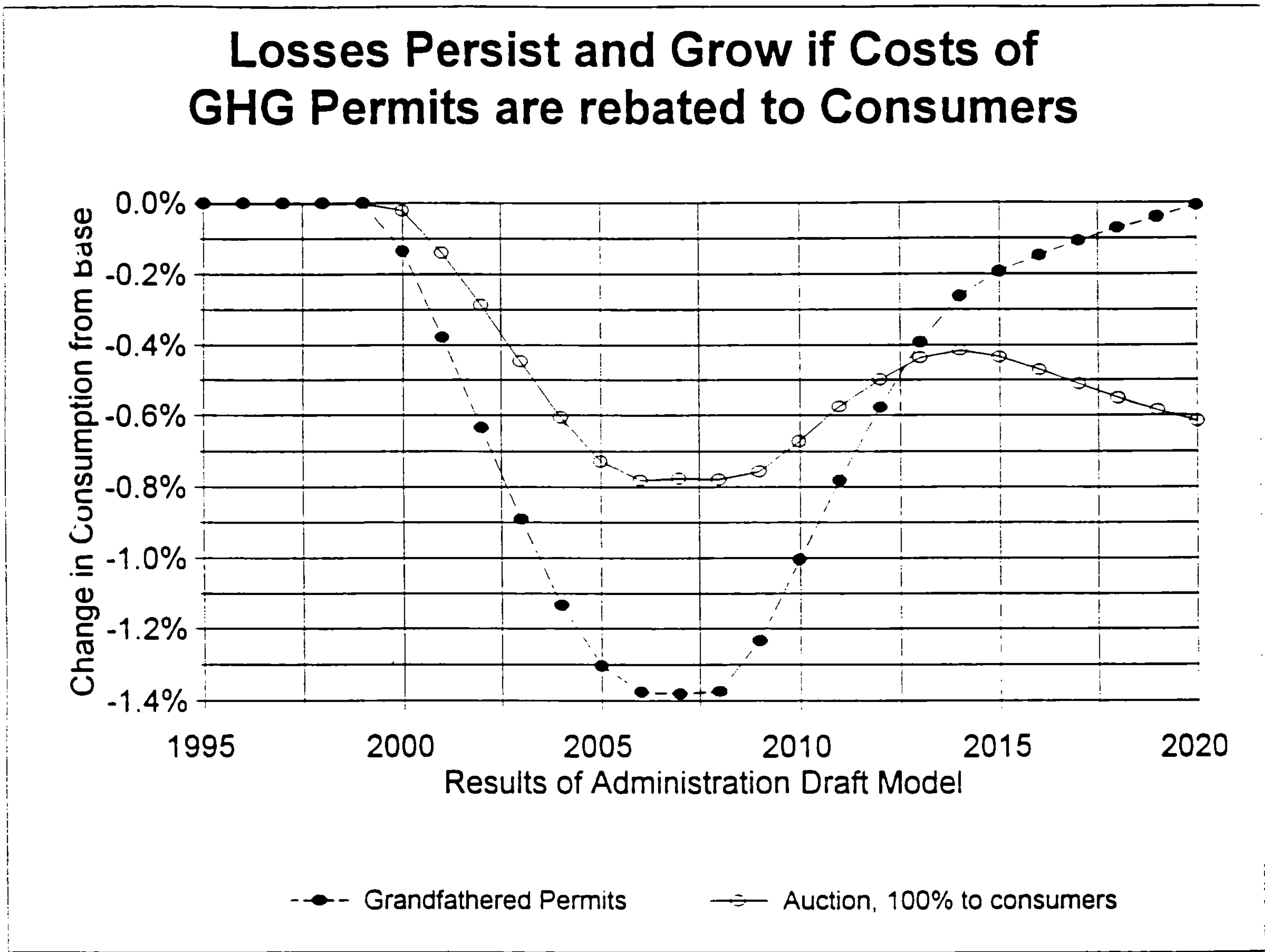
Source: EPI analysis of DRI (1997)

Figure 4



Source: EPI analysis of DRI (1997) and Interagency Analytic Team (1997)

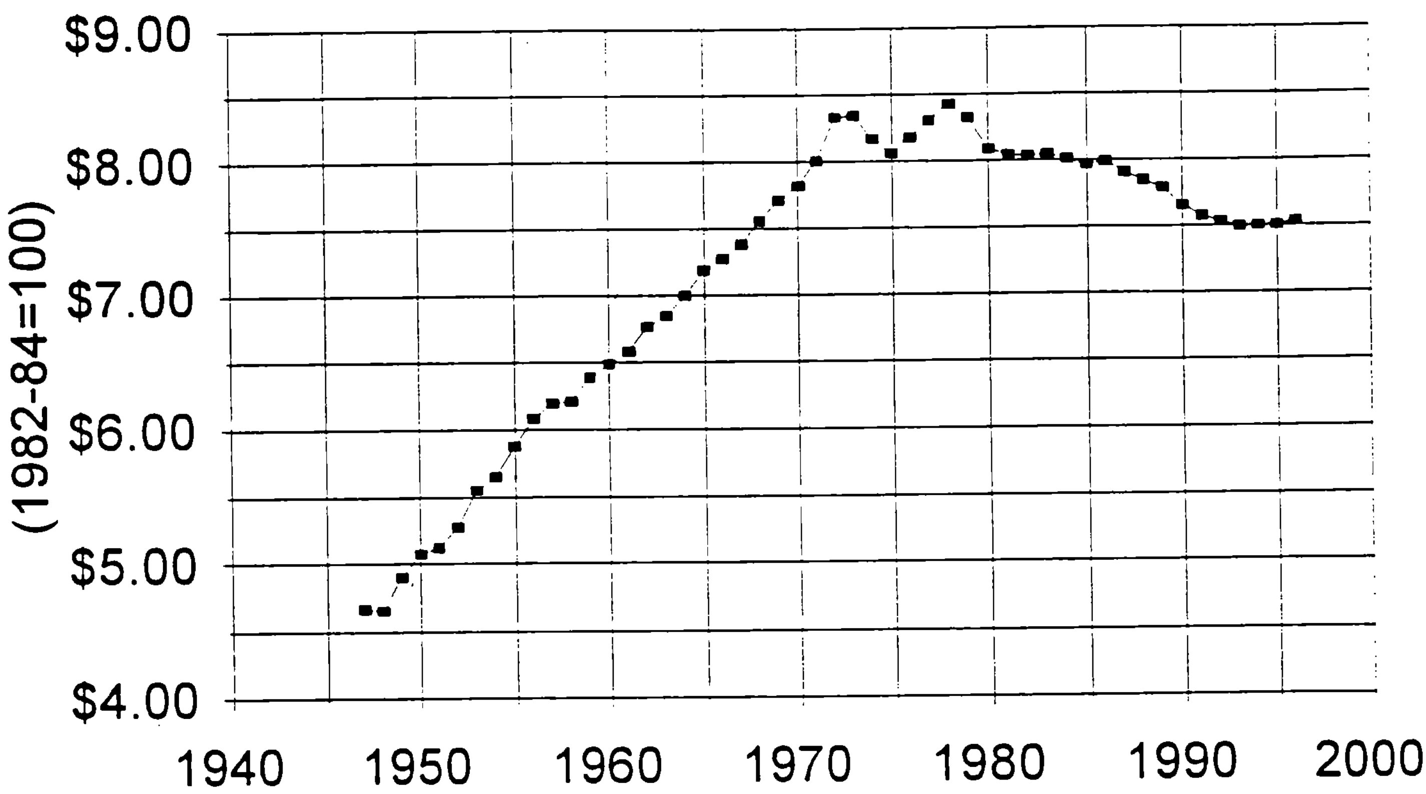
Figure 5



Source: EPI analysis of Interagency Analytic Team (1997)

Figure 6

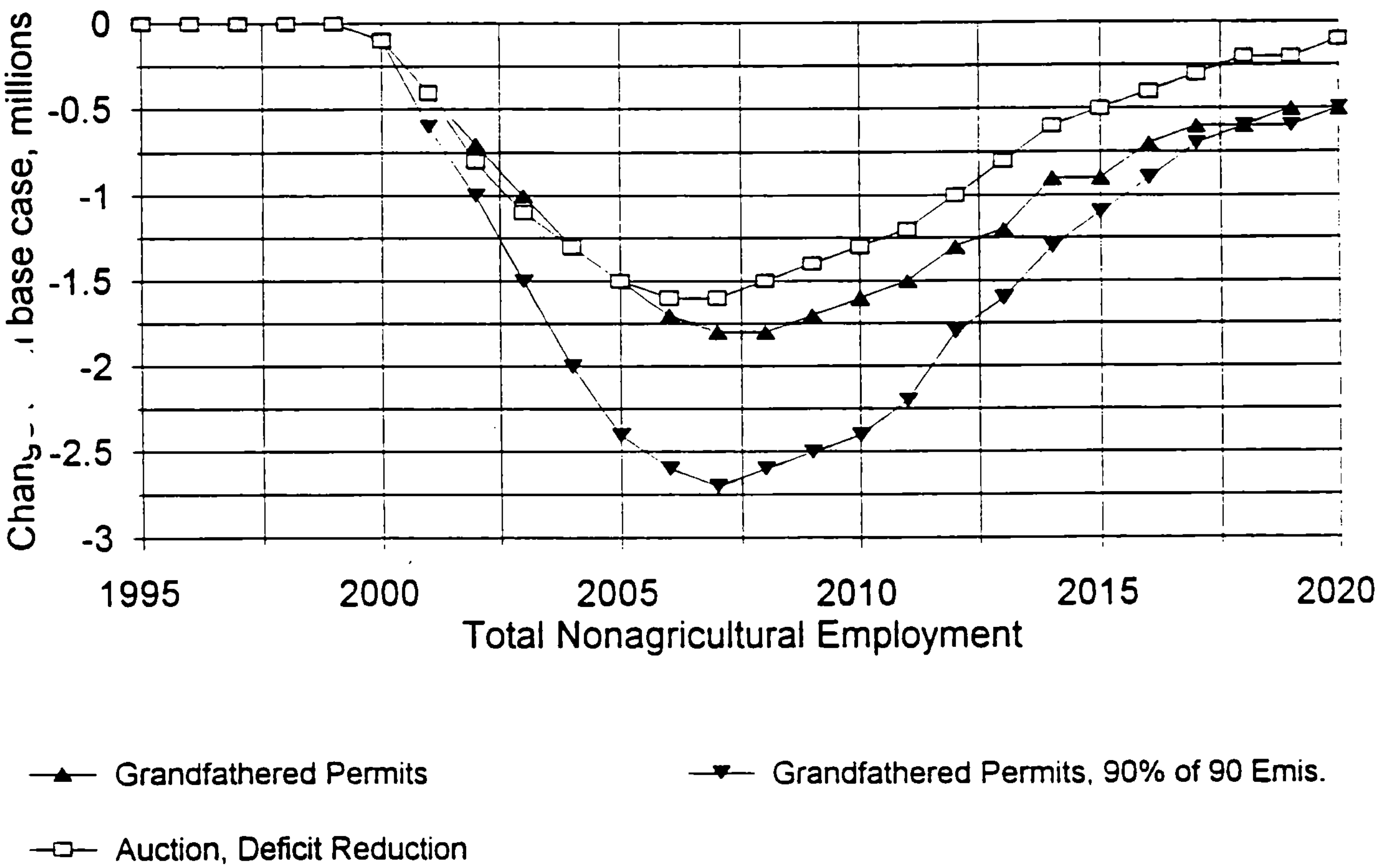
Real Hourly Earnings of Production and Nonsupervisory Workers, 1969-1996



Source: EPI analysis of Bureau of Labor Statistics, "Employment and Earnings." April 1997.

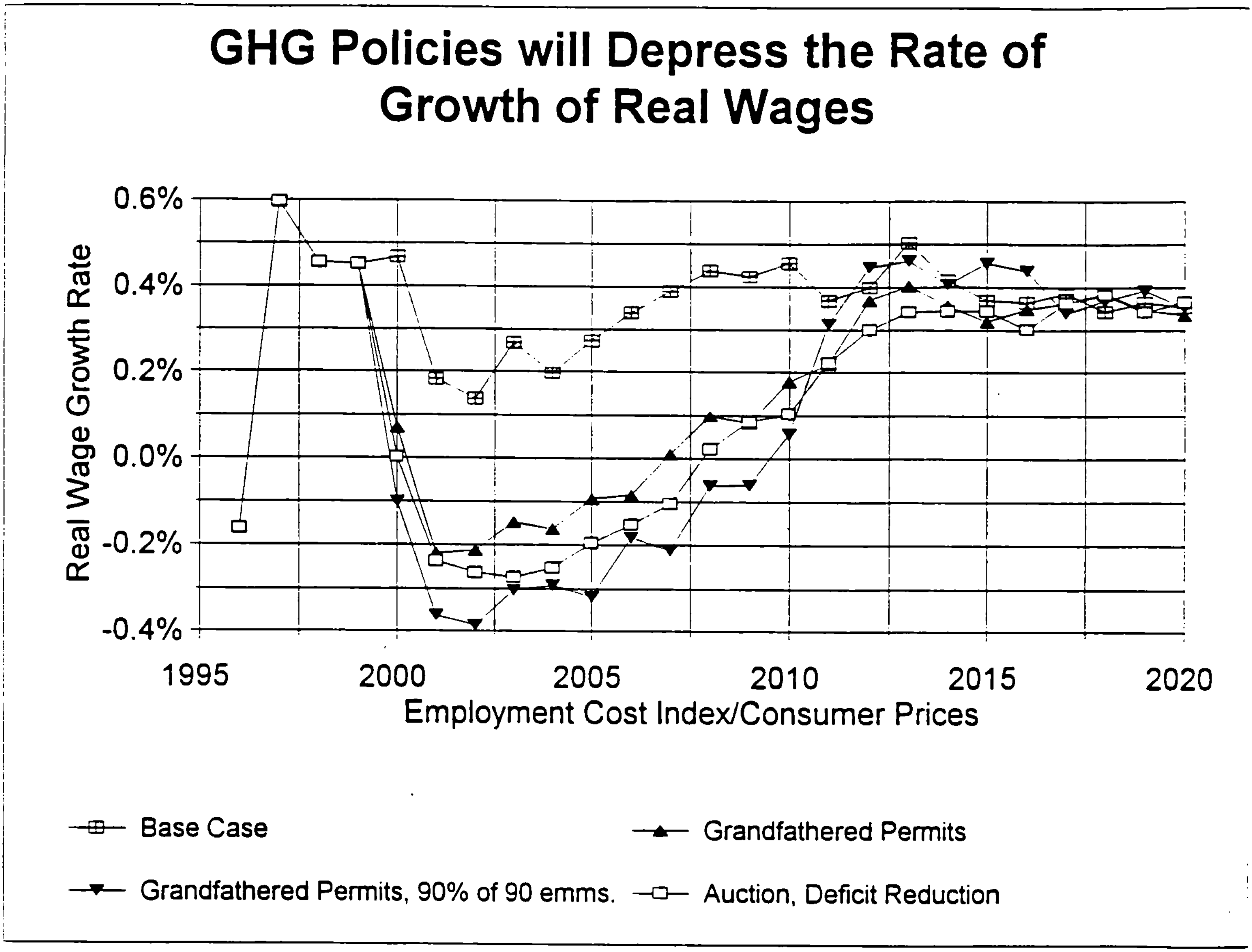
Figure 7

GHG Policies will Reduce Employment Growth by as much as 2.7 Millions Jobs



Source: EPI analysis of DRI (1997)

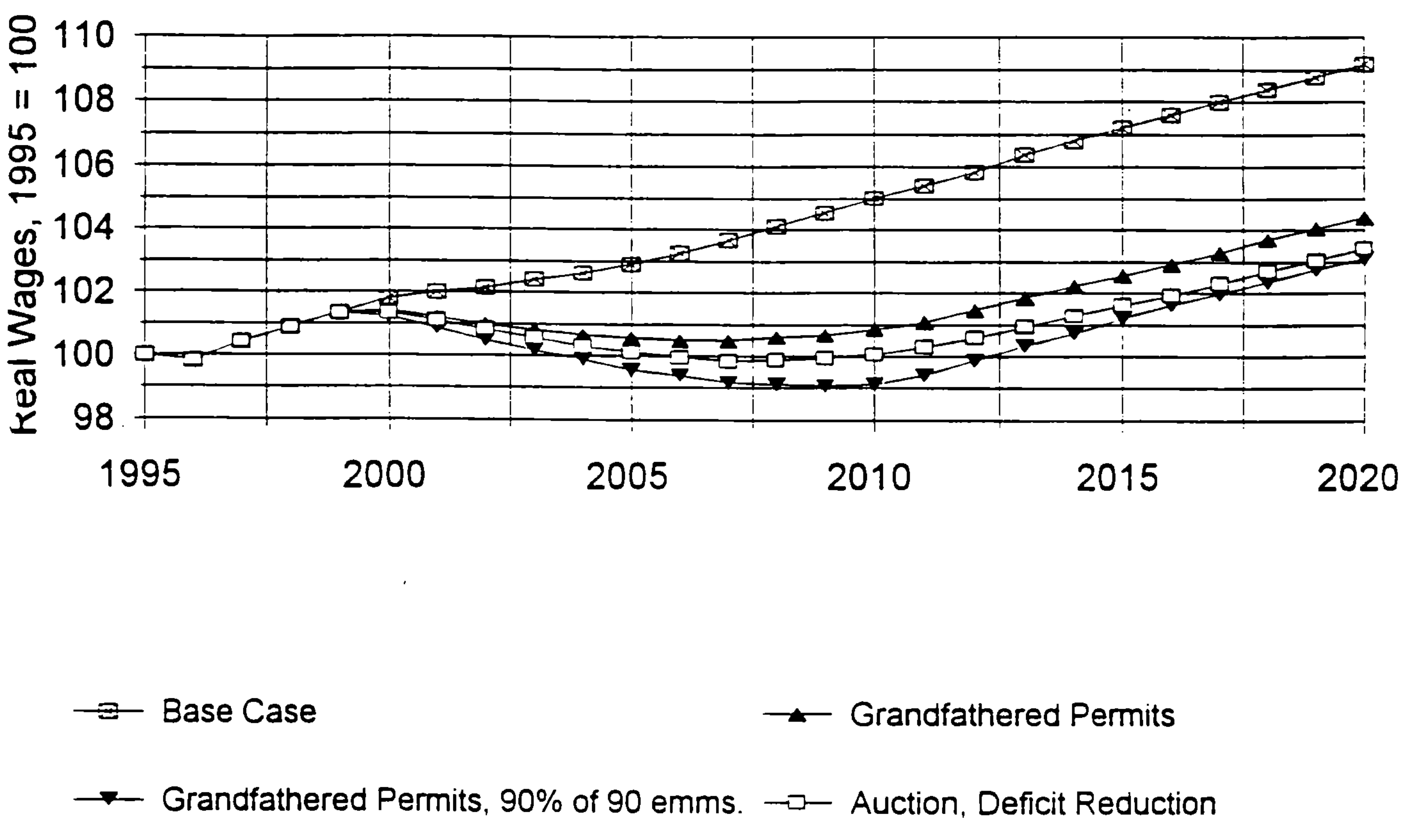
Figure 8



Source: EPI analysis of DRI (1997)

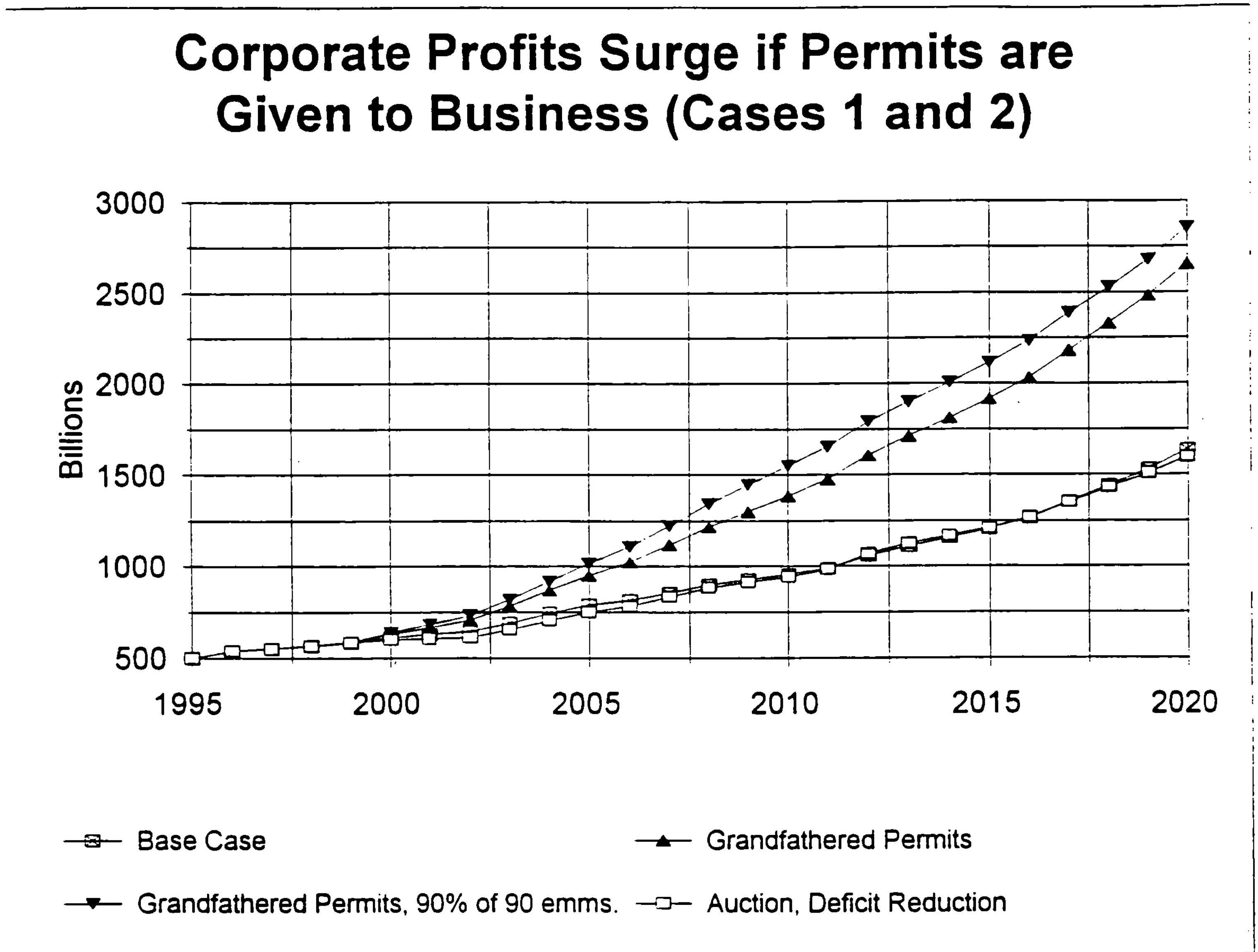
Figure 9

Cumulative Real Wage Growth Will be Cut 50% by GHG Policies through 2020



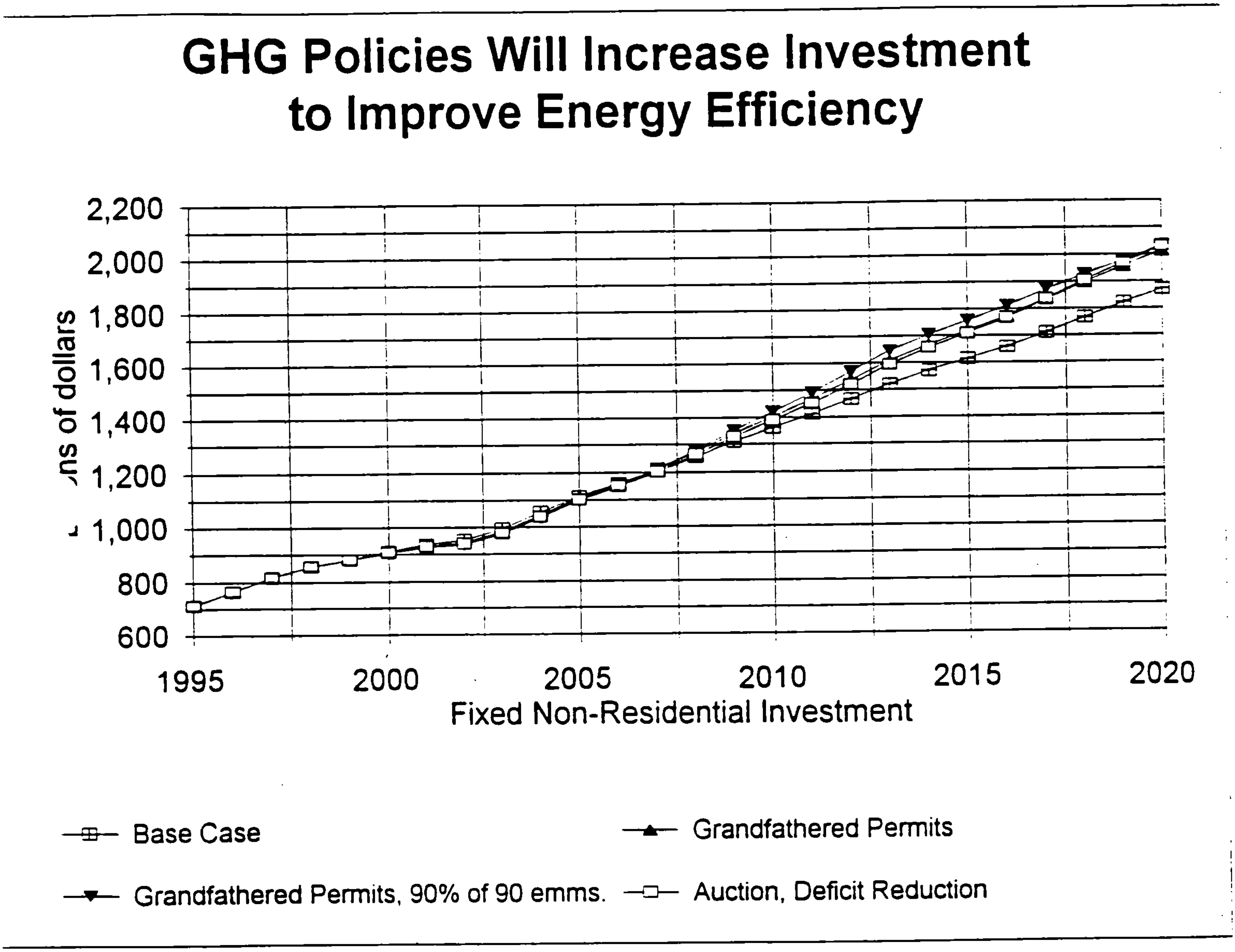
Source: EPI analysis of DRI (1997)

Figure 10



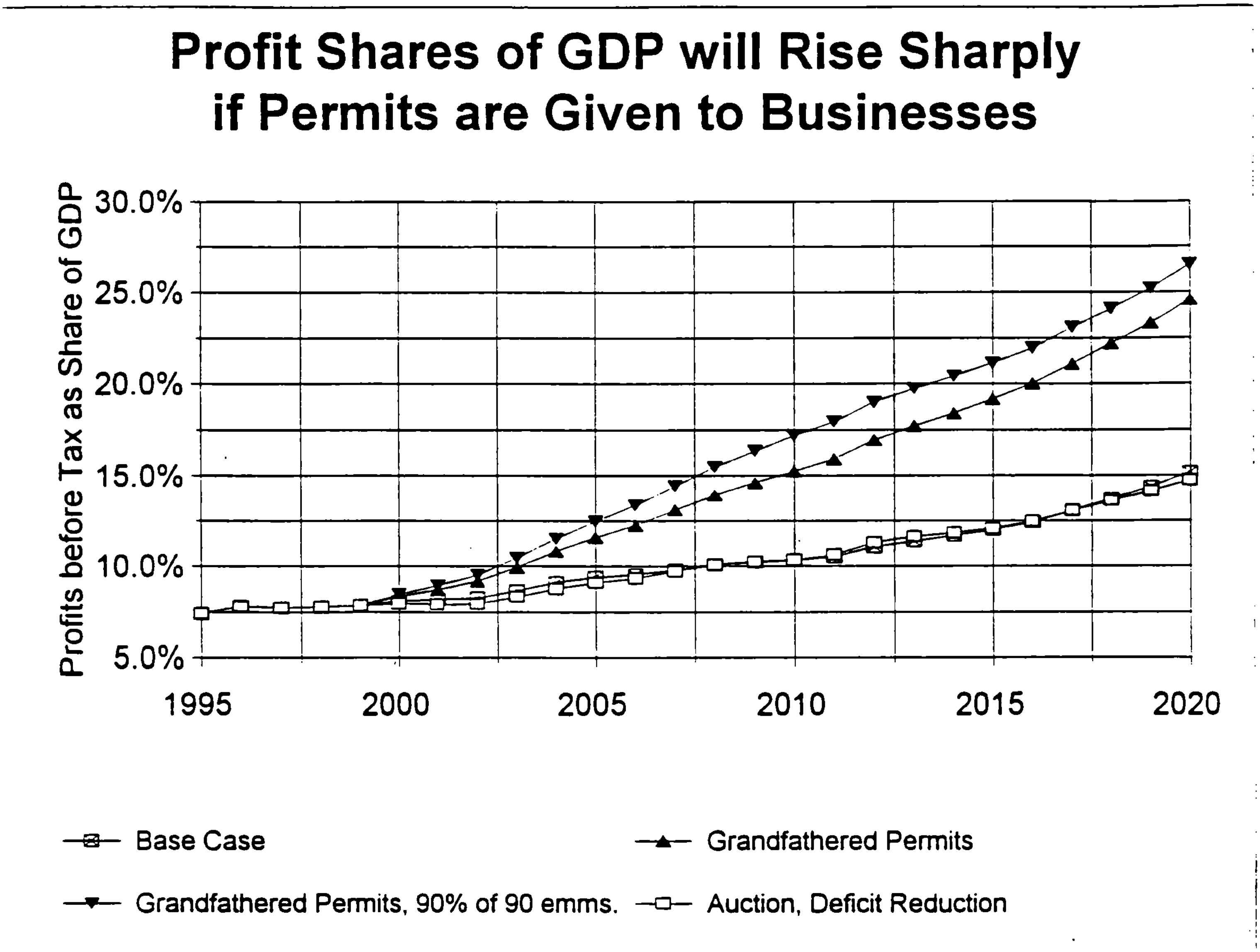
Source: EPI analysis of DRI (1997)

Figure 11



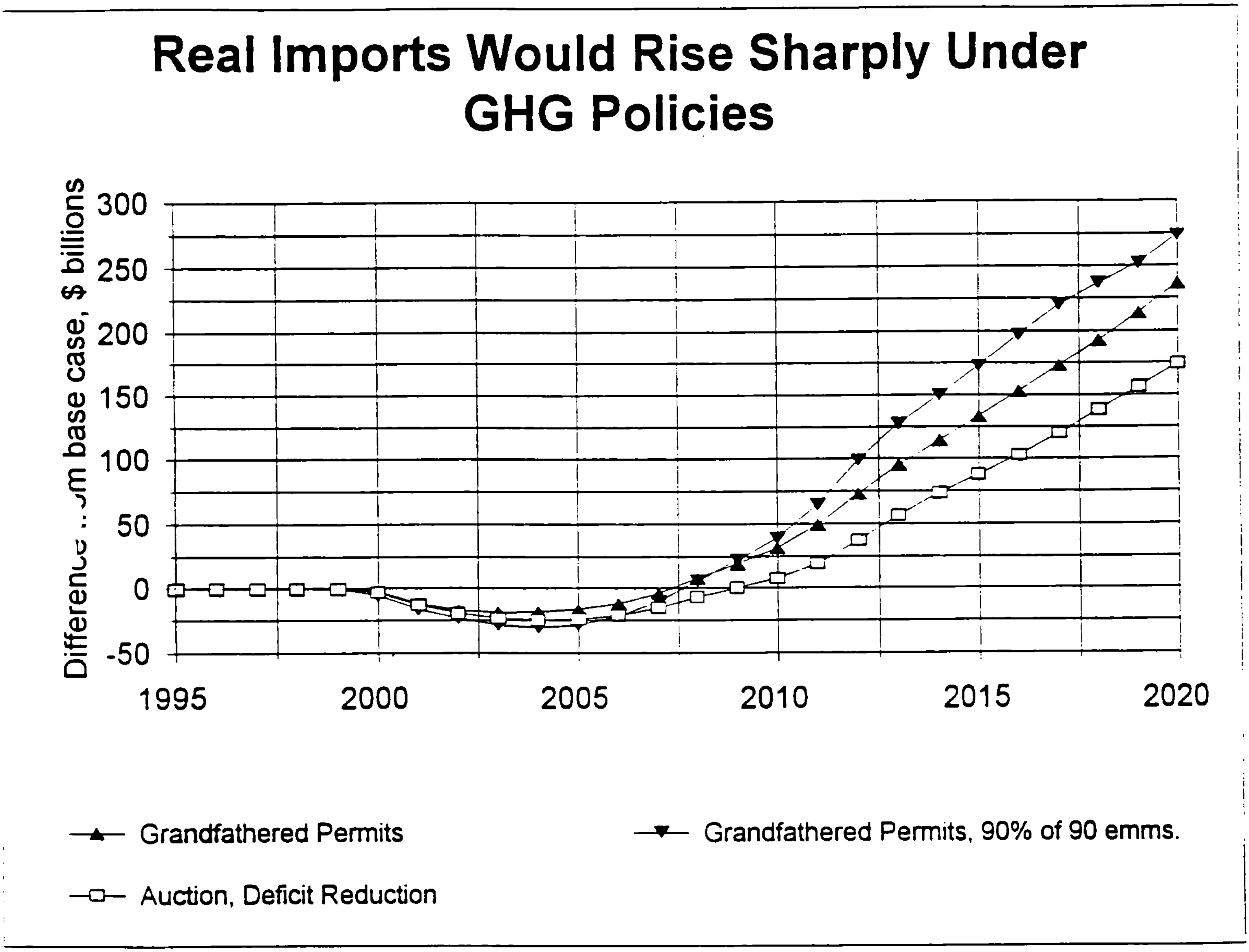
Source: EPI analysis of DRI (1997)

Figure 12



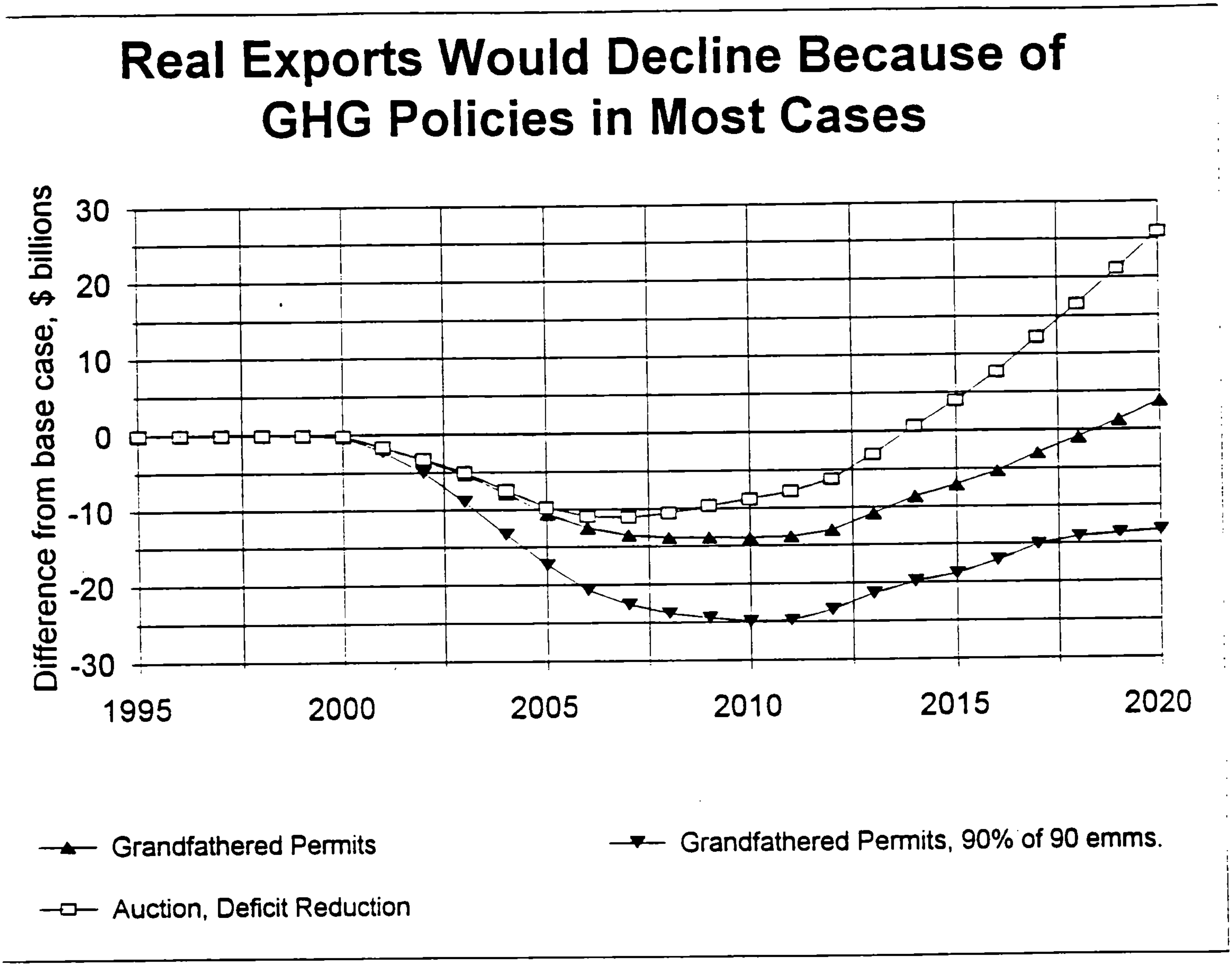
Source: EPI analysis of DRI (1997)

Figure 13



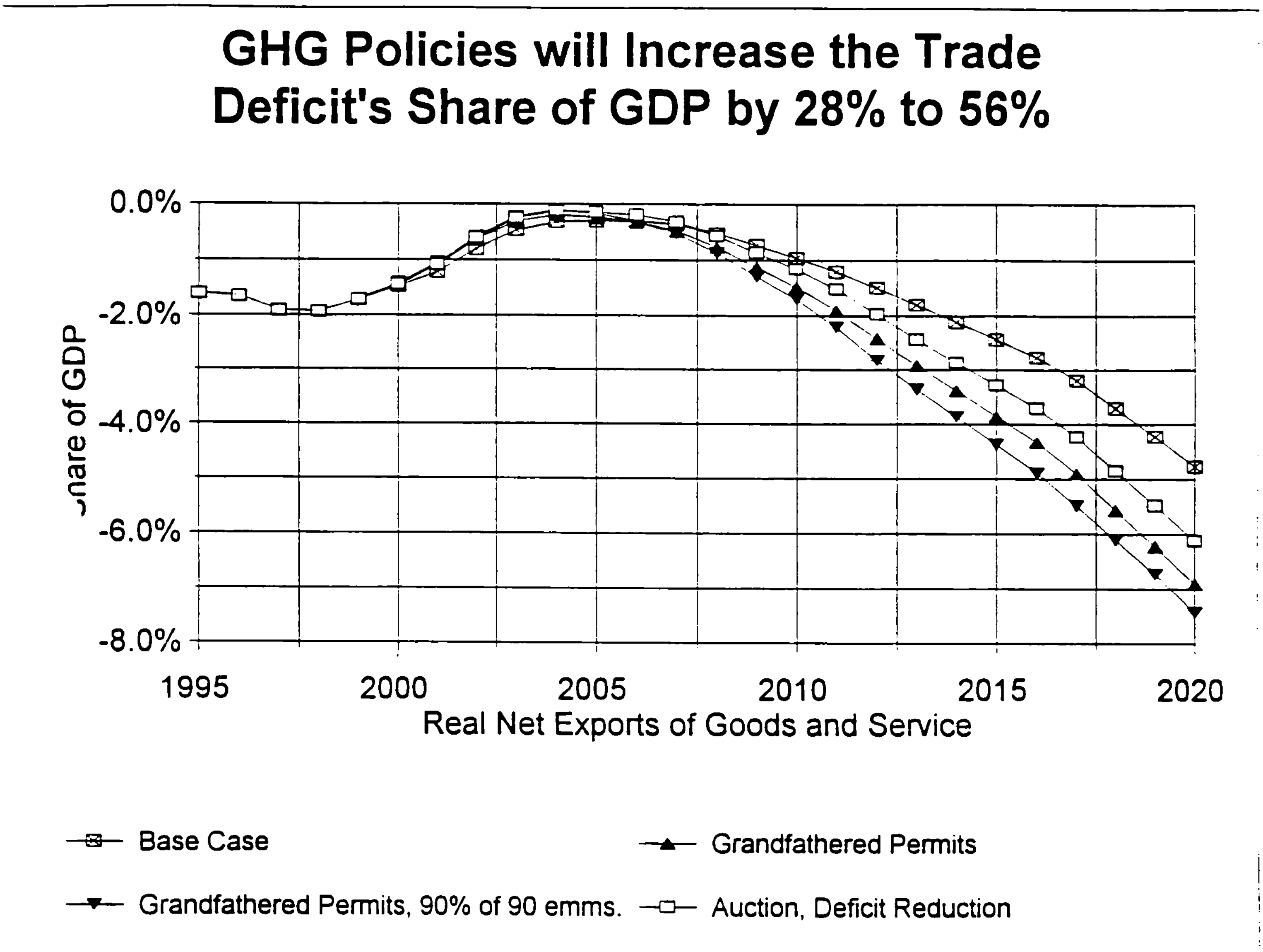
Source: EPI analysis of DRI (1997)

Figure 14



ɔurce: EPI analysis of DRI (1997)

Figure 15



Source: EPI analysis of DRI (1997)

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Divider Title: K

Economic | STRATEGY | Institute

The Global Climate Debate: Keeping the Economy Warm and the Planet Cool

Impact on Five Key Industries: Airlines, Automobiles, Chemicals, Semiconductors and Steel

Andrew Z. Szamosszegi
Lawrence Chimerine
Clyde V. Prestowitz, Jr.

September 1997

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Washington, DC 20005

To date, the debate on global warming has focused primarily on scientific issues and the macroeconomic effects of reduced greenhouse gas emissions.

Because such analysis is based on numerous assumptions and aggregation of numbers, it often misses important elements that can have large effects on individual industries.

The Economic Strategy Institute (ESI) therefore has taken a "bottoms up" approach in this study and looked at the impact of emissions reductions on output, trade and competitiveness of a range of key industries including:

- *airlines*
- *automobiles*
- *chemicals*
- *semiconductors*
- *steel*

We believe these are representative of a range of other industries we did not have the time to analyze.

Finally, we would remiss if we failed to acknowledge the assistance of Hilary Dauer, Andrew Harig, Lisa Hill and Yee Wong in the completion of this report.

-- The authors

Table of Contents

List of Exhibits

Executive Summary

The Issue

- In December 1997, representatives of the world's governments will meet in Kyoto, Japan, to conclude an agreement committing developed countries to mandatory reductions of greenhouse gas emissions to at least 1990 levels by 2010.
- Developing countries are not expected to be included in this agreement, and thus would have no commitments with regard to greenhouse gas emissions, despite the fact that their emissions are rising rapidly and will soon exceed advanced country emissions.
- Such an agreement would have significant implications for the United States, because it could result in substantially higher energy costs and the elimination of production processes that are essential to several key industries.
- The Economic Strategy Institute (ESI) has attempted to estimate the impact of any agreement on the overall U.S. economy, as well as on several key industries (chemicals, steel, autos, passenger airline services, and semiconductors) from the point of view of competitiveness and trade. The key results of this study are summarized below.

The Science of the Issue

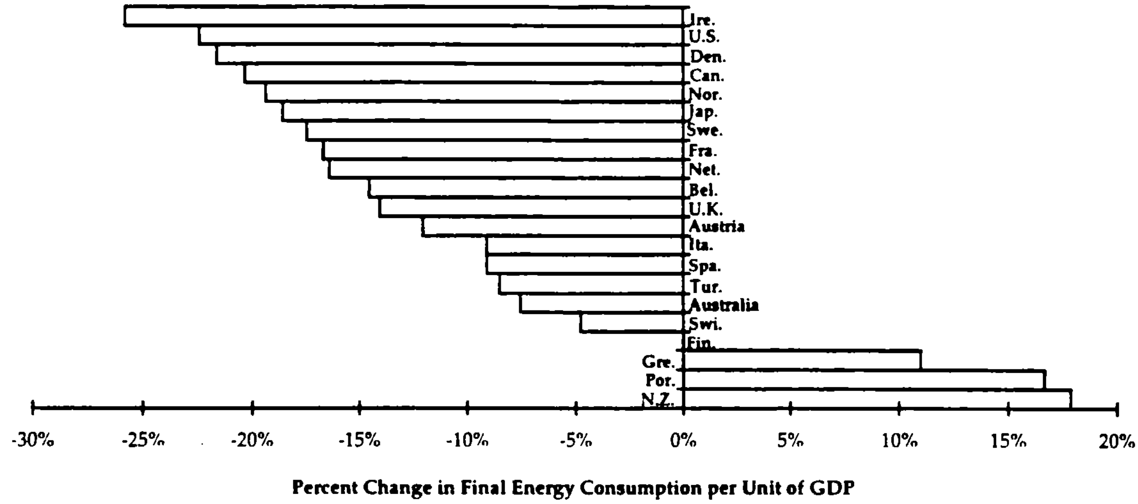
- The science of global climate change is in dispute. Global climate models show temperatures should be rising, but satellite and weather balloon data show temperatures have been stable. ESI's purpose is not to contest the science, but to look at the impact of proposals for dealing with a problem that has not been conclusively proven to exist.

Status of the United States

- Other governments and commentators have asserted that the United States is particularly at fault. This is not the case. U.S. emissions of carbon dioxide per unit of output are below the world average, and most of the rise in U.S. emissions since 1990, the baseline for emissions proposals, reflect population growth and economic expansion, not declining energy efficiency. In fact, U.S.

energy efficiency since 1980 has improved more than that of most industrialized countries.

Exhibit ES.1
Change in Total Final Energy Consumption per Unit of GDP
1980 - 1993



Source: OECD

Survey of Existing Models

- Most of the estimates of the economic impact are based on models which incorporate key economic variables and behavioral relationships. These models contain flaws which lead them to underestimate the economic impact of a greenhouse tax or other measures required to return U.S. emissions to 1990 levels. Optimistic assumptions include:

  -understating the emissions tax necessary to reduce emissions,

  -assuming away the higher costs that would result from increased regulation, and

  -discounting the likelihood that offsetting tax cuts would be used unwisely.

- ESI has concluded that the overall impact on the U.S. economy would be somewhat larger than many models are predicting. This assessment is based on the U.S. experience during and after the oil crises of the 1970s, and on recent model simulations which do not include the rosy assumptions of other estimates. One such simulation, by The WEFA Group, shows that much larger tax levels, perhaps two times larger than the $100 per metric ton of carbon assumed in recent administration simulations, would be required to reduce U.S. emission levels to 1990 levels by 2010.

Exhibit ES.2
Changes in Real U.S. Prices of Various Energy Sources, 1973-1987
Versus Expected Changes Due to a Carbon Tax

	1973-1987	1994-2010
Oil	67%	70%
Natural Gas	223%	45%
Coal	24%	198%

Sources: Derived from data in Gary W. Yohe, *Climate Change Policies, Living Standards, and Real Wage Growth*; Argonne National Laboratory, *The Impact of High Energy Price Scenarios on Energy Intensive Sectors: Perspectives from Industry Workshops*; and ESI Calculations.

Exhibit ES.3
Average Growth Rates of Real GDP
1960-1973 and 1973-1989

	1960-1973	1973-1989
United States	3.95%	2.42%
European Union	4.68%	2.27%
OECD	4.82%	2.63%
OECD Europe	4.67%	2.31%
Japan	9.57%	3.84%

Note: EU, OECD and OECD Europe refer to 1991 membership

Source: OECD

Analysis of Key Industries

- To determine the impact of emissions reduction policies on specific industries, ESI used a bottom-up approach which took into account energy intensities, trade and output levels, the level of sectoral trade with developing countries, foreign direct investment patterns, and the other industry-specific factors. The results show that damage from a greenhouse gas tax would extend to high tech and service industries, as well as to traditional manufacturers. Losses in output and competitiveness would be substantial.

Exhibit ES.4
Estimated Impact of a $100 per Ton Carbon Tax
Summary of Output and Trade Effects by 2010
Percent Change from Base Case

	Output	Exports	Imports
Chemicals			
-with feedstock exemption	-3.3	-3.6	3.5
-without feedstock exemption	-4.6	-7.2	7.0
Steel	-21.9	-18.0	14.3
Automobiles	-5.8	-3.8	3.6
Airline Services	-6.5	-3.0	2.8
Semiconductors*	-8.0	-6.0	5.8

*Semiconductor estimates include the effect of regulations on PFC production
ESI Calculations

- The disturbingly high losses in the semiconductor industry reflect the likelihood that perfluorocarbon emissions (PFCs) would be reduced through regulation. Since there are currently no substitutes for PFCs in the semiconductor manufacturing process, drastic emissions limits would put U.S. manufacturers at a major disadvantage against unregulated competitors from developing countries.
- Exempting developing countries from greenhouse gas limits would dramatically increase the U.S. deficit. With tensions over trade with developing countries already high, support for the World Trade Organization would almost certainly erode. This development would run counter to efforts by this and previous U.S. administrations to open markets and expand free trade.

Conclusions and Recommendations

- Given the ambiguity surrounding the science of global warming and the substantial economic costs of reducing greenhouse gas emissions though taxation and regulation, the U.S. government should be extremely cautious in dealing with the Kyoto agenda. **In particular, it should not agree to proposals being made by other countries for mandatory reduction of emissions by 2010.**
- The United States should resist efforts to exempt developing countries from emissions reduction efforts and encourage cooperative arrangements, financing, and technology transfers that would lead to emissions reductions in developing countries.

- Participants at Kyoto should consider cooperatively financing a Manhattan-type project to achieve massive increases in energy efficiency.

Chapter I: Introduction

In early December 1997, representatives of the world's governments gathering in Kyoto, Japan are expected to finalize a pact committing dozens of countries, including the United States, to reduce emissions of greenhouse gases.[1]

Most man-made emissions are the byproduct of burning fossil fuel for energy, which enables production of goods and services, transportation of goods and people, and simplification of day-to-day tasks. Because energy from fossil fuels has become the driving force of human economic activity, any decisions coming out of Kyoto that affect energy use will inevitably have a far-reaching impact on the global economy. In particular, as the world's largest economy and biggest consumer of fossil fuels, America has much riding on the outcome of these discussions.

Background

In June 1992, at the United Nations Conference on Economic Development in Rio de Janeiro, Brazil, representatives of 154 governments signed the Framework Convention on Climate Change. The ultimate aim of this treaty, which took force on March 21, 1994, is to prevent any climate change that could result from high concentrations of atmospheric greenhouse gas. As part of efforts to reach this goal, Annex I countries (the OECD countries as of 1992, plus Eastern Europe and the old Soviet Union) voluntarily committed to reduce greenhouse gas emissions to 1990 levels by the year 2000.[2]

Since Rio, there have been two major meetings of the Climate Change Convention. The first conference of the parties (COP-1), occurred in Berlin in late 1995. Participating ministers concluded that the voluntary commitment mechanism was insufficient and consequently adopted the Berlin Mandate, which exempted developing countries from emissions limits while beginning the process of setting post-2000, mandatory limits on developed country emissions. The Ad Hoc Group of the Berlin Mandate was tasked to devise a legal

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[1] Greenhouse gases are carbon dioxide, water vapor, methane, nitrous oxide and tropospheric ozone. Man-made chemicals, such as chlorofluorocarbons, hydrofluorocarbons and perfluorocarbons, act as greenhouse gases and could be affected by Kyoto discussions as well.
[2] The United States objected to an explicit treaty commitment during negotiations, but changed its stance in April 1993.

instrument that would commit developed countries to more stringent targets after 2000.

In July 1996, at COP-2 in Geneva, Switzerland, participants stressed the need to strengthen the Climate Change Convention. The Kyoto meeting in December 1997 will be the third conference of the parties, and is aimed at agreeing to strict, mandatory emissions limits for Annex I countries.

Issues

From the outset, the treaty has been controversial. Many scientists worry that the science underlying climate change predictions is too uncertain to warrant hasty, drastic action. Outside the scientific community, concern is mounting that the proposals to be discussed at Kyoto represent unrealistic, panicked reactions that could lead to slower economic growth and lower living standards - a high price to pay for solving an uncertain problem.

The Science

Though the scientific debate is beyond the scope of this paper, it deserves mention because the Intergovernmental Panel on Climate Change (IPCC), an international network of scientists, presents itself as representing the scientific consensus on global climate change. IPCC scientists have concluded that "... the balance of evidence suggests that there is a discernible human influence on global climate;"[3] that man-made greenhouse gases will lead to significantly warmer weather during the next hundred years; and that warmer temperatures will result in more extreme weather changes in some areas, including more severe or less severe floods and droughts.

The IPCC's predictions of impending global warming and its impact, however, are not universally accepted. Hundreds of scientists at the Rio conference signed the Heidelberg Appeal, which warned against concluding a treaty without a proper scientific basis. In 1996, nearly one hundred climate scientists signed the Leipzig Declaration, questioning the validity of global warming forecasts based on computer model simulations.[4]

The record of the models predicting climate change is uncertain at best. In the mid-1980s, available models were forecasting a 5.2°C (9.4° F) average rise in global temperatures by 2100. By 1992, the IPCC had modified that estimate to a range of 1° to 4.5°C (1.8° to 8.1°F) through 2050. For its second assessment, the group revised its upper bound estimate down to 3.5°C (6.3°F) by 2100.

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[3] IPCC, *Climate Change 1995: The Science of Climate Change*, Working Group 1 (Cambridge, UK: Cambridge University Press, 1996), 6.

[4] S. Fred Singer, "Scrap the Climate Treaty," *The Journal of Commerce* (March 6, 1997).

Scientists who disagree with even these most recent projections argue that the computer models generating these estimates do a poor job of reflecting natural climatic variability.[5] They also cite data from satellites and balloon-borne sensors showing little-to-no climate change since 1979 and little, if any, warming since 1945, even though seventy percent of all manmade greenhouse gases have been added to the atmosphere during the past fifty years.[6] They conclude that there will be warming, but much less than the IPCC predicts, and it will have benign, perhaps even beneficial, consequences.[7]

Dissension within the scientific community is not an excuse for inaction. However, the many unanswered questions surrounding this scientific debate suggest a prudent, measured approach toward abatement is warranted.

The Proposals

The Ad Hoc Group of the Berlin Mandate has waded through emissions control proposals submitted by various countries and has combined them into a negotiating text that will be modified and adopted in Kyoto. Though no firm targets for emissions reductions have been chosen, it is clear that the emissions reductions proposals now under consideration, if adopted, would have a major impact on the global economy during the next several decades. Key points of contention include:

1) Emissions targets and timetables - Proposals range from reducing carbon dioxide emission levels to 1990 levels by 2010 to cutting twenty percent from 1990 levels by 2020. Earlier target dates and deeper emissions cuts will mean more severe economic adjustments.
2) Developing-country exemption - Emissions from non-Annex I countries are expected to surpass Annex I emissions by 2050, yet the Berlin Mandate has decreed that their emissions will be allowed to grow for the foreseeable future. Any plan that exempts developing countries would encourage the migration of energy-intensive production processes to developing countries and would result in little net emissions reduction.

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[5] William K. Stevens, "Warming Skeptic Says It's a Lot of Hot Air,"

[6] Patrick J. Michaels and Paul C. Knappenberger, "The United Nations Intergovernmental Panel on Climate Change and the Scientific 'Consensus' on Global Warming," in John Emsley, Ed., *The Global Warming Debate* (London: The European Science and Environmental Forum, 1996), 165-166.

[7] Some believe that such slightly higher temperatures and carbon dioxide levels will lead plant life and human civilization to thrive. See, for example, Sherwood Idso, "Plant responses to Rising Levels of Atmospheric Carbon Dioxide," in Emsley, Ed., *The Global Warming Debate* (London: The European Science and Environmental Forum, 1996), 28-39; and Thomas Gale Moore, "Why Global Warming Will Be Good for You," *The Public Interest* (Winter 1995), 83-99.

3) Differentiated targets - The European Union expects to reach its target by allowing some members to increases emissions while others reduce theirs. Some countries are arguing that all Annex I countries should have the targets appropriate to their economic profile.
4) Flexible reduction strategies - There are alternatives to achieving a target by a certain date. The United States, for instance, has suggested an approach that would allow for emissions budgets to be achieved over a number of years. Washington has also suggested emissions trading and joint implementation, schemes which would, in essence, enable developed countries to get credit for encouraging "offshore" emissions reductions.

Regardless of which proposal emerges from COP-3, any amendment to the treaty that mandates emissions reductions will ultimately affect the choices of both firms and consumers. Whether Annex 1 governments decide to reduce emissions by implementing tough new standards, typically referred to as command and control measures, or by implementing market-oriented measures, such as carbon taxes or tradable permits, there will likely be a decline in the growth of Annex I GDP. These losses would occur because emissions reduction policies would compel companies to make investments that are more expensive than those that would have taken place in the absence of such policies.

During the past decade, dozens of studies have attempted to estimate the economic costs of mitigation. A clear majority of them conclude that GDP in OECD countries would decline from the levels that would be expected to occur in the absence of mitigation policies.[8] Of the ninety-four studies of individual OECD countries cited in the IPCC's second assessment, only seven show gains to baseline GDP from the reduction of carbon dioxide emissions. All twenty-three global impact studies cited by the IPCC conclude that global output will decline as a result of carbon abatement efforts.[9]

Most of these estimates were derived from top-down models that look at the aggregate macroeconomy as a whole. There have been a small number of bottom-up, energy-based, models as well.

This Study's Contribution

Despite the number of studies already completed, there are a wide range of topics that have not yet received adequate attention. For instance, the effects of mitigation policies on employment, inflation, trade and competitiveness at both

[8] IPCC, *Climate Change 1995:Economic and Social Dimensions of Climate Change,* Working Group III (Cambridge, UK: Cambridge University Press, 1996), 303-322.
[9] *Climate Change 1995:Economic and Social Dimensions of Climate Change,* 336.

the aggregate and sectoral level have barely been analyzed.[10] In addition, analysts have ignored the potential impact of an ill-conceived, growth-distorting climate change agreement on advanced-country support for free trade. A climate change agreement that results in slower advanced-country growth, higher unemployment, and a sharp rise in developing-country imports could give substantial ammunition to people arguing that trade with developing countries is intrinsically bad.

With this in mind, the Economic Strategy Institute (ESI) has undertaken a bottom-up study that quantifies the potential impact of carbon abatement measures on key U.S. industries, covering both high-tech manufacturing and service sectors. In particular, ESI has focused on the chemical, iron and steel, automobile, air transport, and semiconductor industries. The analysis focuses on the absolute economic impact on those industries, as well as the relative impact that proposed measures would have on their competitiveness and on trade flows.

These industries represent a broad cross section of the U.S. economy. Steel and chemicals are traditional "smokestack" industries. Steel is an important input in a variety of manufactured goods, and it increasingly faces competition from developing countries and transition economies. The U.S. chemical industry is also energy intensive and is dominated by multinational corporations capable of shifting production to developing countries. The automobile and airline industries are less energy intensive, but demand for their end-use products and services will be significantly affected by abatement policies that raise gasoline prices and reduce economic growth. The semiconductor industry, a key player in America's industrial renaissance and high-tech revolution, is not energy intensive but, nonetheless, is a major energy user and uses a greenhouse gas in the production process. The potential impact of abatement policies on this cutting edge industry is particularly worth exploring in view of the expectation that U.S. industry will increasingly move from smokestack to high-tech sectors.

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[10] See, for example, *Climate Change 1995:Economic and Social Dimensions of Climate Change*, 13; and "Research on Linkages between Trade, Environment and Sustainable Development - A Preliminary Note," posted online by the United Nations Department for Policy Coordination and Sustainable Development at gopher://gopher.un.org/00/esc/cn17/1996/backgrnd/research.txt.

Chapter II: Putting U.S. Emissions Performance in Perspective

Since enacting the National Environmental Policy Act in 1969, the United States has played a leading role in addressing global environmental problems.[11] Despite this positive record on environmental issues, the United States this year has come under increasing criticism for its policy toward global climate change.

Specifically, European leaders and environmentalists around the globe have been taking the U.S. government to task for not making more progress toward the goal of reducing U.S. carbon dioxide emissions to 1990 levels by 2000, and for not embracing a European plan to reduce emissions further by 2010. Continental leaders, such as British Foreign Secretary Robin Cook, have criticized Americans for being "...still very much in a culture of large, extravagant private cars and generous consumption of energy as a cheap commodity."[12] Europeans are also fond of pointing out that the United States is responsible for more than one-fifth of global carbon dioxide emissions.

For its part, Europe is portraying itself as the defender of the planet. The European Union as a whole could very well reach its 2000 goal, and European leaders have embraced the goal of cutting emissions fifteen percent below 1990 levels by 2010.

European efforts to caricature the United States as the bad boy of global climate change are misguided, however. The timing of the E.U. cacophony - it began in June 1997 at the G-7 Summit in Denver - suggests it was part of a concerted effort to deflect attention from crawling economies and high unemployment back home. More telling, the data simply do not back European assertions. Though it is true that the United States emits more than twenty percent of the world's carbon dioxide, the United States is responsible for only eighteen percent of total greenhouse gas emissions.[13] Since the United States produces more than twenty percent of the world's economic output, the country's greenhouse emissions per unit of growth are actually better than average.

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[11] Organization for Economic Cooperation and Development (OECD), *Environmental Performance Reviews - United States* (Paris: OECD, 1996), 215.
[12] See, for example, "G-7 Summit Split over Greenhouse Gases," *San Jose Mercury News* (June 21, 1997).
[13] OECD, *Environmental Performance Reviews*, p. 217. Sulfur dioxide and nitrous oxides are also considered greenhouse gases.

The reality, then, is quite different from what E.U. leaders would have us to believe. The United States has done much to reduce greenhouse gas emissions over the years, and other factors, less sensational than the pejorative "extravagant culture," help explain current U.S. emission levels.

Poor Timing

The decision at Rio to base future emissions targets on 1990 emissions levels has placed an added burden on the U.S. economy, making it even more difficult for the United States to keep its year-2000 promise. Saddam Hussein's invasion of Kuwait nudged the U.S. economy into recession in 1990. Since energy use, and thus emissions, tend to ebb and flow in tandem with economic activity, U.S. emissions of carbon dioxide that year were 125 metric tons below 1989 levels and did not surpass 1989 levels until 1993.[14] By contrast, the economies of Japan and Europe were in the midst of expansions that lasted until 1992.[15] Thus, meeting any targets based on 1990 levels will be relatively less taxing for Europe and Japan than for the United States.

In fact, the choice of 1990 as a baseline year has been beneficial to Europe. For example, both Germany and Great Britain will likely attain their targets for 2000. Their success, however, has nothing to do with climate change policies and everything to do with timing.

Germany is receiving credit for emissions reductions occurring in the former East Germany, where coal was the main energy source and energy use was inefficient. Since 1990, the united Germany has been dismantling noncompetitive production facilities in the eastern part of the country, and many of the remaining factories are underutilized.[16] Germany's emissions picture, therefore, has brightened dramatically. In Denver, and at the United Nations meeting on climate change that followed, German Prime Minister Kohl was among those critical of the United States, despite the fact that carbon dioxide emissions in western Germany have actually risen since 1990.[17]

In Great Britain, the story is similar. During the late 1980s, Britain's Conservative government decided to cut back on massive subsidies supporting the country's inefficient mining operations, a decision that had nothing to do with climate

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[14] OECD, *OECD Environmental Data Compendium 1995* (Paris: OECD, 1995), 39.
[15] The United Kingdom is the exception. Its recession also began in 1990.
[16] See, for example, Paul M. Bernstein, W. David Montgomery and Thomas F. Rutherford, *World Economic Impacts of U.S. Commitments to Medium Term Carbon Emissions Limits*, CRA No. 837-06 (Washington, DC: American Petroleum Institute, January 1997), 18.
[17] Jeff Rubin, "A Betrayal of Rio," ABCNEWS.com (June 28, 1997).

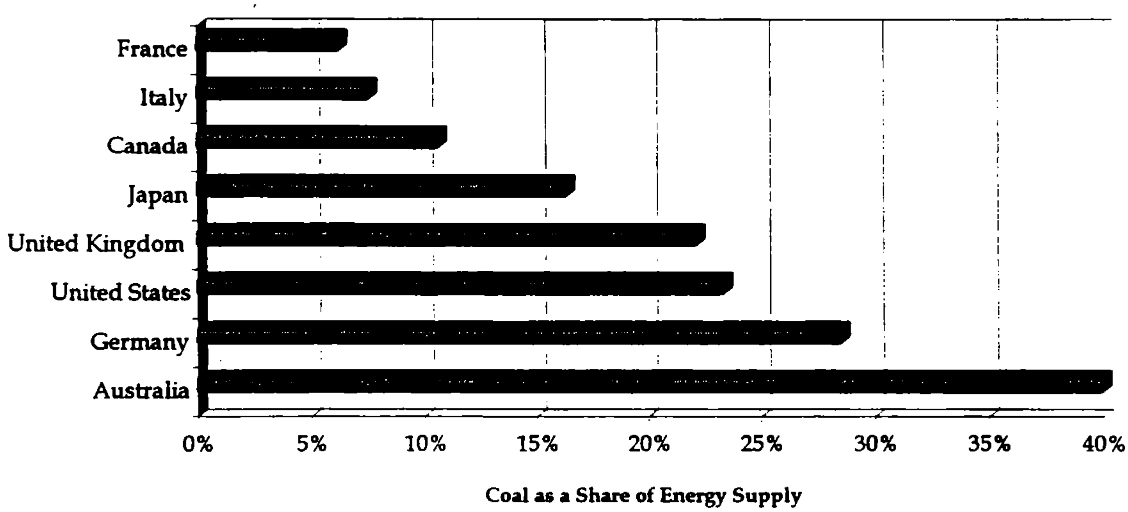
change policies and everything to do with fiscal necessities. As a result, Britain's deregulated electric power generating industry has abandoned coal for cheaper and cleaner natural gas, causing Britain's emissions to plummet. Prime Minister Tony Blair and Foreign Secretary Robin Cook have subsequently voiced the loudest criticism of the United States, which seems ironic in view of the fact that, as shadow trade and industry secretary of the Labor Party, Cook had virulently opposed Conservative efforts during the 1980s and 1990s to reduce coal mine subsidies.

Factor Endowments

It is often said that America's greatest assets are its natural resources and its people. Interestingly, this interplay of people and resources - coal and land, in particular - goes a long way toward explaining current U.S. emissions levels.

The United States, like Australia, has been blessed with large coal reserves. Unlike Great Britain and Germany, where mining has been heavily subsidized and inefficient, U.S. mines are extremely efficient and cost effective. Naturally, the U.S. electric power industry, as well as energy-intensive industries that generate their own power, long ago turned to coal as a primary source of energy. In 1995, the United States supplied more than one-fifth of its total energy consumption and fifty-four percent of its electricity with coal, more than most other advanced economies (see exhibit II.1).

Exhibit II.1
Share of Coal in Total Energy Supply, 1995

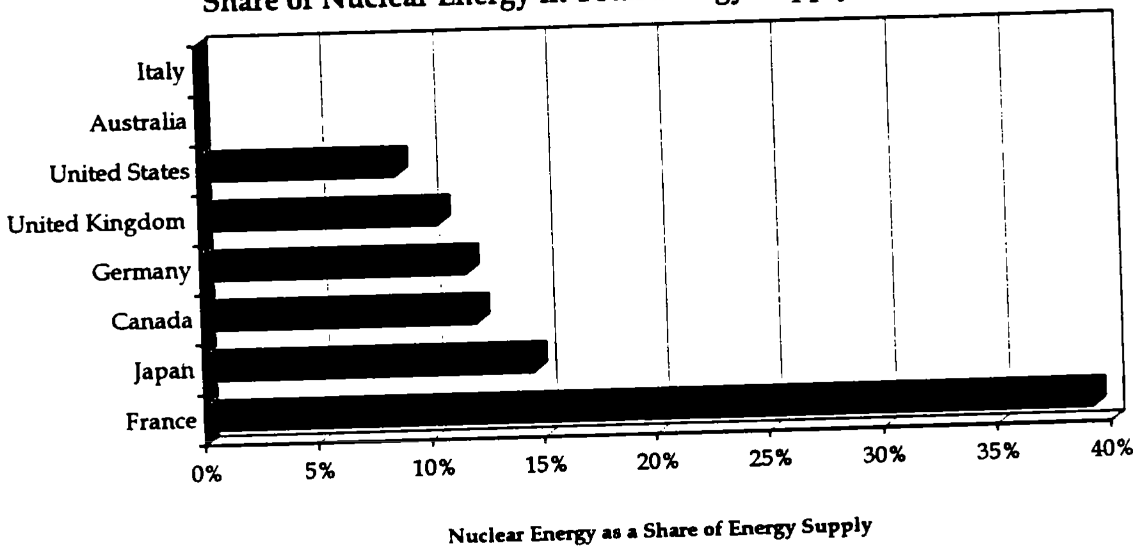


Source: International Energy Agency

This dependence on coal makes good economic sense, but it increases U.S. emissions levels, because coal is the most carbon-intensive of the fossil fuels. One unit of coal produces about eighty percent more carbon dioxide than does one unit of natural gas, and twenty percent more than one unit of petroleum.[18]

Like other countries, the United States has turned to non-fossil-based energy sources, such as nuclear energy. Due in large measure to protests by environmental groups, however, nuclear energy supplies less than ten percent of U.S. energy consumption, well below penetration levels in France and Japan (see exhibit II.2). In 1980, nuclear energy accounted for about eight percent of France's primary energy supply, versus about four percent in the United States. The nuclear share of French energy is now about forty percent, five times higher than in the United States, and French carbon dioxide emissions from energy use have declined more than twenty percent from 1980 levels. With federal licenses for many U.S. nuclear power plants beginning to lapse, and with deregulation of the U.S. electricity market around the corner, experts predict that the nuclear share of the America's electricity market will be halved in twenty years.[19]

Exhibit II.2
Share of Nuclear Energy in Total Energy Supply, 1995

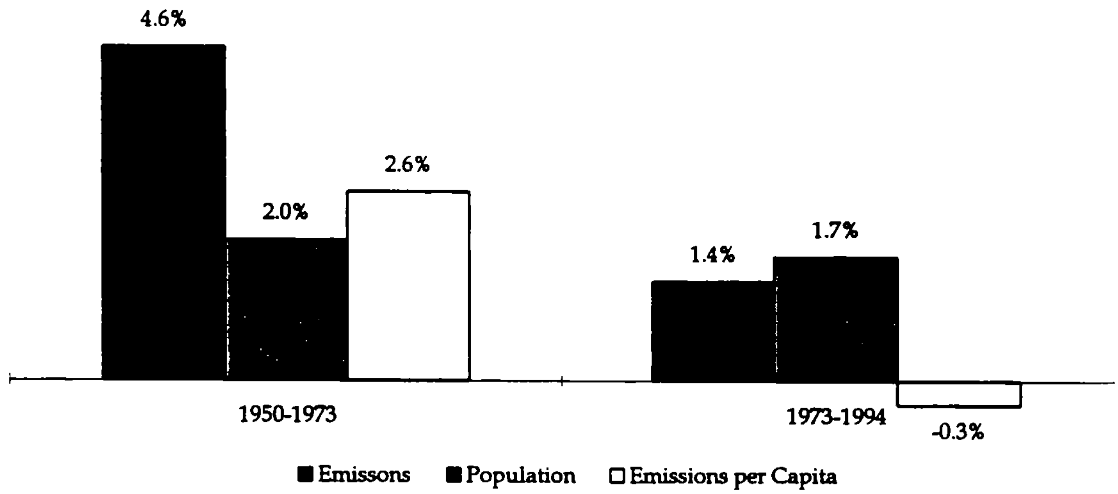


Source: International Energy Agency

Emissions growth in the United States is also a function of rising U.S. population and employment levels. All other things being equal, a growing population leads to higher energy usage and, thus, to higher carbon emissions. In fact, during the past two decades, global emissions levels have been driven by population growth, but per capita emissions of carbon dioxide have actually been declining (see exhibit II.3).

[18] Intergovernmental Panel on Climate Control, *Climate Change 1995 – Impacts, Adaptations and Mitigation of Climate Change: Scientific-Technical Analysis* (Cambridge, UK: Cambridge University Press, 1996), 14.
[19] Margaret Kriz, "Fuel Fight," *National Journal* (June 7, 1997), 1128.

Exhibit II.3
Annual Changes in Global CO_2 Emissions, Population, and Per Capita Emissions
1950-1974



Thus, looking solely at national emissions growth over time can be deceptive. For instance, the United States is being criticized because it is going to miss its 2000 target by an estimated thirteen percent. Japan, on the other hand, is expected to fall short by only six percent. However, the difference in emissions growth can be explained entirely by differences in population growth. According to the U.S. Bureau of the Census, the U.S. population is expected to expand by 10.7 percent between 1990 and 2000, while Japan's population is expected to advance by only 3.3 percent.[20] In other words, per capita emissions in both countries are expected to rise by roughly 2.5 percent.

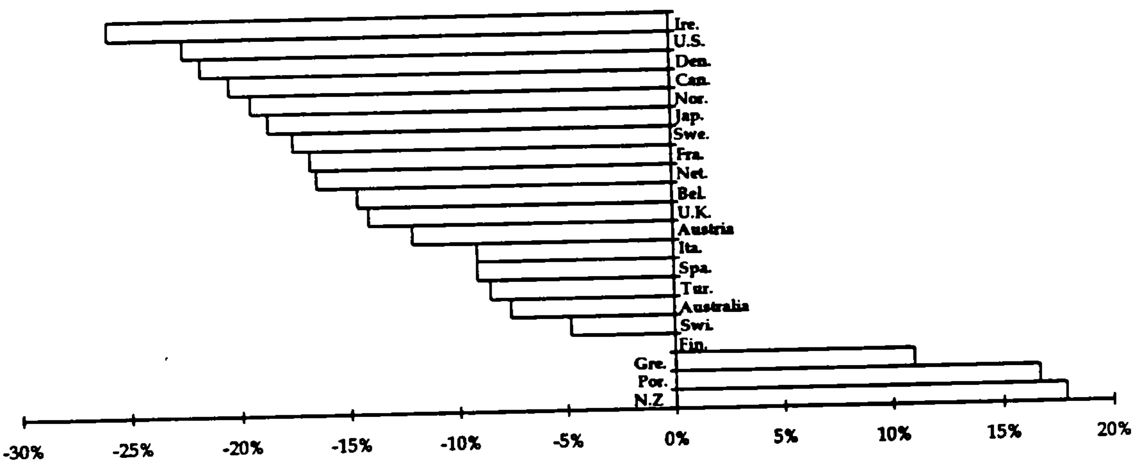
The United States' low population density is another reason U.S. emissions levels are relatively high. Exhibit II.4 plots a statistically significant relationship between population density and emissions, as a share of GDP, in nineteen OECD countries. On the graph, these countries are divided into two groups, each with a trend line. Both trend lines have negative slopes, indicating that countries with lower population densities are associated with higher emissions levels.

[20] National Trade Data Bank, "Total Mid-Year Population & Projections to 2050."

We're Not That Bad

As the Kyoto meeting approaches, critics increasingly will portray the United States as an environmentally unfriendly country. The reality is quite different. Since 1980, U.S. final consumption of energy per unit of output has declined dramatically. The exhibit below indicates that, by this measure, the United States has improved twenty-two percent, more than all but one industrialized country (see exhibit II.7). U.S. emissions intensity, the ratio of carbon emissions to GDP, declined twenty-one percent during the period. Clearly, in the absence of improved energy efficiency, U.S. emissions in 1993 would have been much worse.

Exhibit II.7
Change in Total Final Energy Consumption per Unit of GDP
1980 - 1993

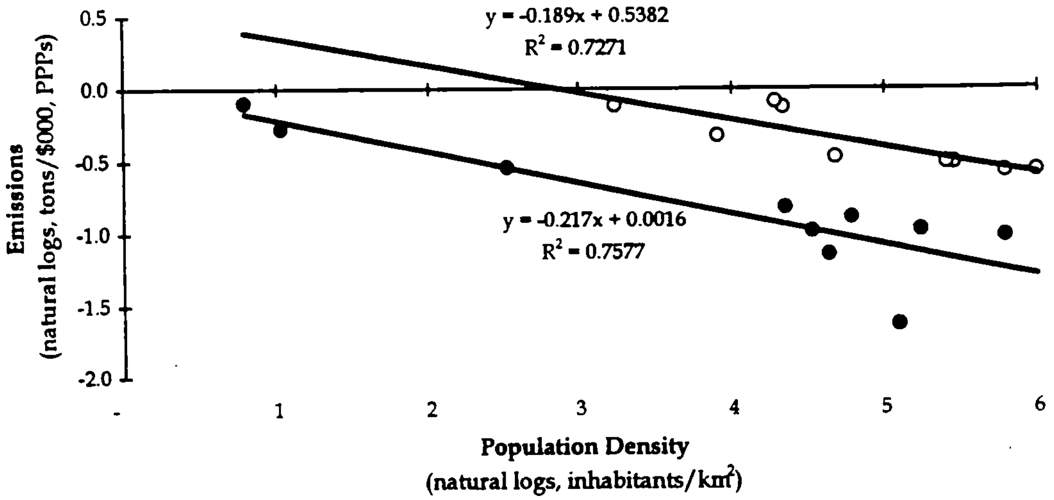


Source: OECD

Even in more recent years, the United States performance has continued to be admirable. From 1990 to 1993, the latest year for which complete OECD emissions data is available, the United States was among eleven OECD countries that reduced emissions levels while increasing economic output (see exhibit II.8). From 1990 to 1995, the United States reduced emissions per unit of output by seven percent, versus a one percent reduction for Canada and a one percent increase for Japan.[24]

[24] For GDP based on 1991 purchasing power parities, see OECD, *Environmental Data Compendium.* For emissions data, see EIA, *Emissions of Greenhouse Gases in the United States;* Giles Gherson, "PM's Eco-ambivalence," *The Edmonton Journal* (June 27, 1997); and htpp:/www.geic.or.jp/geic-jpinfo.html.

Exhibit II.4
Population Density and Emissions, as a Share of GDP, in Select OECD Countries, 1990



Source: IEA and OECD

It is intuitive that countries with geographically dispersed populations, such as the United States, Canada and Australia, would require more energy than would more crowded industrialized countries. An analysis by the International Energy Agency (IEA) of the OECD supports this interpretation. According to surveys, lower population density within U.S. cities and towns appears to compel Americans to use automobiles for local trips that would be convenient enough for Europeans and Japanese to make by bicycle, foot, or local transit.[21] Lower population density also encourages greater use of air travel and results in greater energy use and emissions in the transport of freight, especially raw materials, because U.S. freight forwarders must ship goods further than do their counterparts in other countries.[22]

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[21] International Energy Agency (IEA), *Indicators of Energy Use and Efficiency*, (Paris: OECD, 1997), 103.
[22] IEA, *Indicators*, 117.

basis, the U.S. record holds up quite well, both in the aggregate and in specific sectors. The analysis in this chapter also indicates that proposals that do not take into account economic growth and population growth discriminate against countries with faster growing economies and populations. This and other shortcomings of existing proposals will be discussed in Chapter III.

Chapter III: Proposals for Kyoto - What's Out There?

Since COP-1 concluded that further measures would be needed to reduce greenhouse gas emissions in developing countries beyond 2000, several countries have tabled proposals and have suggested specific policies. The Ad Hoc Group of the Berlin Mandate is in the process of sifting through the various proposals with the goal of drafting an accord that will be the subject of the Kyoto meeting in December. With December fast approaching, a number of issues remain the subject of intense discussion, and all of them are important to the United States. In the near future, U.S. negotiators will have to take a stand on each of these issues.

Emissions Targets and Timetables

One of the more contentious issues is how deeply, and over what time period, the Annex I countries should cut their carbon dioxide emissions. Earlier target dates and deeper emissions cuts imply more severe economic adjustments for the United States and other developed countries.

The most draconian proposal, proffered by the Association of Small Island States (AOSIS), calls on the Annex I countries to cut their carbon dioxide emissions twenty percent below 1990 levels by 2005. Because it is becoming increasingly clear that most Annex I countries will be unable to cut their emissions to 1990 levels by 2000, this proposal is destined to fail. Earlier this year, the European Union proposed that developed countries cut emissions of a basket of greenhouse gases fifteen percent below 1990 levels by 2010. Though more reasonable than the AOSIS plan, the E.U. proposal is probably unobtainable as well.

Japan, the host of COP-3, has a special interest in seeing negotiations succeed. In August, the Japanese government proposed a two-phase plan that is less taxing than the E.U. and AOSIS proposals. During the first phase, the developed countries would be required to cut annual per capita carbon dioxide emissions to three metric tons per person. During the second phase, average annual emissions from 2010 to 2015 would have to equal the 1990 baseline. In essence, the Japanese proposal delays the Rio goal by fifteen years.

The United States has not yet come out in favor of any specific targets or timetables, but has proposed an "emissions budget" in lieu of a single year target. According to the U.S. proposal, each Annex I country would be allocated an emissions budget, which it would draw down over a given period of time. Any amount not used during the budget period could be used in future budget periods. Conversely, countries could borrow emissions from the future, but would be assessed a penalty.

Today's controversy over targets and timetables exists because Rio set the bar too high.[27] The likely failure of all but two OECD countries to reach their targets indicates that the goal of returning to 1990 emissions levels by 2000, agreed upon in 1992, was ill-conceived. Moreover, Germany and the United Kingdom, the countries with a chance of meeting the 2000 deadline, have benefited from special circumstances (see Chapter III). Eight years is simply not enough time for governments to build a durable political consensus or to make the necessary policy changes, nor is it enough time for consumers and businesses to alter their investment and consumption patterns in a way that would minimize the impact of such policies on economic growth.

Likewise, some other proposals currently before the Ad Hoc Group, if adopted, would fail for similar reasons. Proposals promoting draconian targets even earlier than Rio's less sweeping goals have been achieved have understandably heightened the worries of businesses and their workers alike. More reasonable emissions targets, phased in over a longer period of time, would be more credible, evoke less opposition, and give policymakers time to devise measures to minimize the adverse economic consequences of carbon abatement.

Of course, building a durable consensus on the need for targets and timetables would require unassailable evidence that anthropogenic emissions are indeed responsible for global climate change, and that climate change poses a serious danger to the environment. As long as scientific uncertainty continues to exist, extended timetables are more appropriate.

Developing-Country Exemption

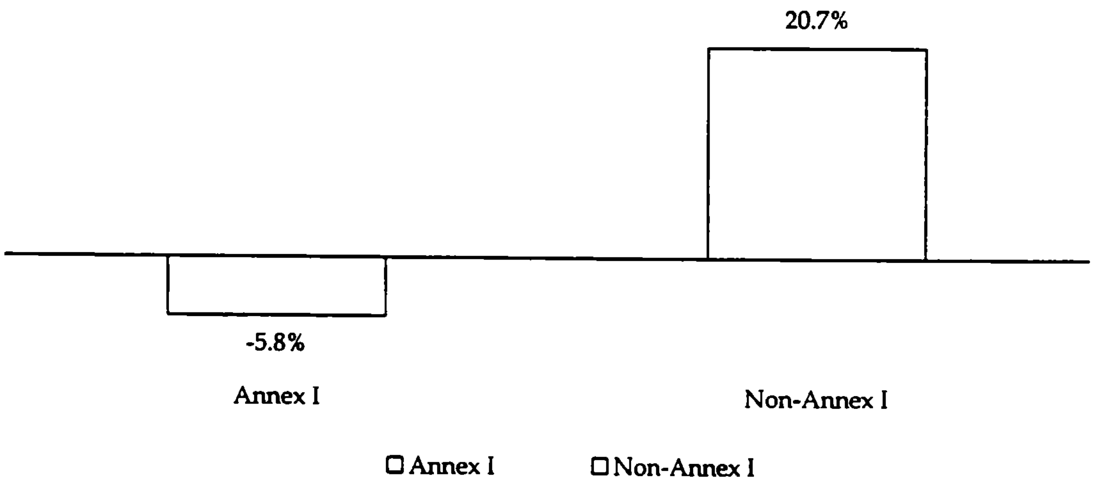
Emissions from non-Annex I countries are growing rapidly and should surpass Annex I emissions by 2020, yet the Berlin Mandate decreed that developing country emissions will be off the table at Kyoto. The rationale for this exemption is straightforward. Increased energy usage typically occurs hand-in-hand with

[27] Roger Bate, "Rio Set the Bar Too High," *Wall Street Journal* (), .

economic development. Developing countries argue that limiting their emissions now would hamper their ability to increase living standards.

If the global community is serious about controlling carbon dioxide emissions, however, there is no alternative to bringing the non-Annex I countries into the process as soon as possible. As the figure below demonstrates, these countries' emissions have risen faster between 1990 and 1995 than have Annex I emissions.

Exhibit III.1
Change in Emissions of Carbon Dioxide, 1990-1995
Annex I vs. Non-Annex I Countries



Sources: http://www.eia.doe.gov/oiaf/ieo96/appa1.html; ESI calculations

Though it is true that the emissions levels of OECD countries in Annex I also grew during this period, no one doubts that emissions of developing countries, with their rising populations, growing economies and greater dependence on solid fuels, will surpass those of advanced countries. The implication of this trend is clear. Even if Annex I emissions are kept at 1990 levels, global emissions will continue to grow unless something is done to harness developing-country emissions.

Despite the Berlin Mandate's prohibition of targets for developing-country emissions, the United States has suggested a mechanism that would reduce non-Annex I emissions without stunting growth. Known as "joint implementation," it would allow developing countries, with the help of technology and financial aid provided by an Annex I country, to create emissions reduction credits by undertaking projects that lead to lower emissions. These credits would then be acquired by the Annex I country that helped implement the emissions reducing project.

It should also be recognized that the extraction of commitments from non-Annex I countries has implications beyond the global climate change negotiations. In particular, failure to get non-Annex I countries involved will color U.S. attitudes toward trade deals with developing countries. Securing such deals has been a major trade policy goal of the current administration and many members of Congress, but past debates on the merits of these agreements have been contentious and divisive. Whether it was the hyperbole accompanying the actual debates, or the adverse impact of the peso crisis on the U.S. trade balance with Mexico after the NAFTA, many believe that trade with developing countries has worked against the United States. A Kyoto accord that gives developing countries a competitive advantage over the United States could only inflame these feelings, making support for future market-opening deals less likely.

Differentiated Targets

Some countries, notably Australia, argue that requiring equal emissions reductions among Annex I countries unfairly discriminates against countries with energy-intensive industrial structures and growing populations. Australian officials contend that Annex I countries should have targets appropriate to their economic profiles. The European Union, in fact, which expects to reduce emissions fifteen percent by 2010, has embraced this approach for its members. For example, Great Britain has promised to reduce emissions by twenty percent while Portugal will be allowed to expand its emissions by forty percent. Curiously, the European Union has argued against extending this approach to other Annex I members.

The Australian position makes more sense than the cookie-cutter approach. Given the variations among Annex I economies, it seems unreasonable to expect every country to be able to achieve the same level of reductions over an equivalent period of time. This is especially important for the United States, because, as indicated earlier, the U.S. record in controlling emissions is better than the critics suggest, and also because many of the current proposals would place an unfair burden on the United States. The budgeting idea proposed by the administration, discussed above, takes a small step in the appropriate direction by providing additional flexibility over the "x" percent reduction-by-date-certain approach fashioned at Rio.

Emissions Reduction Strategies

Negotiators are also wrestling over what specific abatement policies or measures, if any, should be included in the document to be considered at the Kyoto meeting. Among the many alternatives are removal of energy and transport subsidies ("no regrets" policies), financial incentives to promote energy efficiency, carbon and energy taxes, energy efficiency standards for traded products, and voluntary public-private agreements.

Washington has promoted the idea of emissions trading among countries, which would enable Annex I countries or their companies to purchase emissions credits from countries that have substantially reduced their emissions. The practical hurdles to creating an emissions trading regime are daunting, however. Emissions trading on a global basis would require some type of centralized monitoring institution and a formula for calculating initial emissions budgets. Obviously, if mandatory reductions come out of Kyoto, it is in the United States' best interest to preserve the flexibility to reduce emissions in the least costly manner.

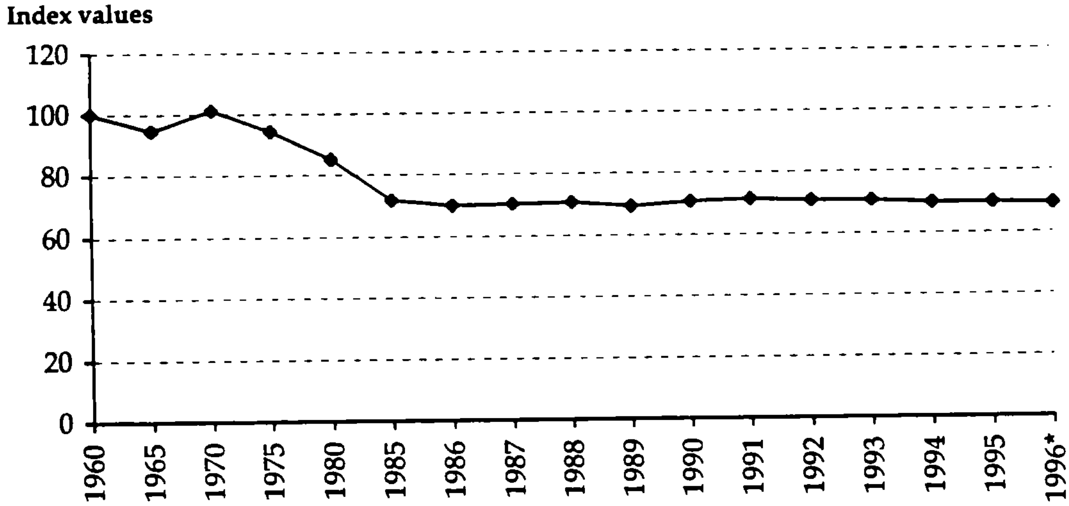
Chapter IV: Measuring the Macroeconomic Impact of Emissions Control

This chapter focuses on the question of how to measure the potential economic impacts of global warming proposals. A careful examination of existing estimates suggest that the short-to-medium-term costs are likely to be much higher than commonly believed. Estimates indicating that the transitional economic costs would be small, and only temporary, are particularly flawed.

How Will The Economy Be Affected?

Almost all manmade CO_2 emissions come from the burning of fossil fuels. Reducing emissions requires reversing the growth of energy consumption, and/or shifting to energy sources that produce less emissions. This could only be accomplished in one of three ways: by improving energy efficiency (i.e., reducing the ratio of energy consumption to GDP), by slowing economic growth (to reduce energy demand), or by developing commercially viable energy alternatives. The more difficult it is to improve energy efficiency or develop fossil fuel alternatives, the greater the slowdown in economic growth needed to achieve any targeted level of energy savings. For example, limiting America's energy consumption in the year 2010 to 1990 levels would require an improvement in energy efficiency of about 2.3 percent per year (the expected trend in real GDP growth) to avoid any adverse effect on real output – a level of improvement far above recent efficiency gains (see exhibit IV.1). In the absence of commercially viable energy substitutes, anything less would mean slower economic growth.

Exhibit IV.1
U.S. Energy Consumption, Real GDP Index, 1960-1995



* Preliminary figure
Sources: U.S. Department of Energy/Energy Information Agency; and *Economic Report of the President 1997*

Theoretically, improvements in energy efficiency can be encouraged through regulatory change or energy taxes. For simplicity's sake, most existing quantitative studies combine all energy conservation measures into ar equivalent carbon tax on all fossil fuels.

A tax increase is generally considered more effective, and less costly, than command-and-control regulations because it works through market mechanisms. However, taxes affect the economy in a number of ways and ultimately influence overall economic growth, employment levels, and living standards. The magnitude of these effects are determined by a number of factors, including:

- The sensitivity of energy efficiency to the tax increase. Significant improvements in efficiency through fuel substitution, pure conservation, and modernization, would limit economic costs.

- The impact on U.S. inflation. The level of inflation will be determined by the level of changes in energy prices, and by how these price increases affect other the prices of consumer and capital goods and services.

- The impact on disposable income and corporate profits. The level of disposable income will depend upon the increase in inflation at t consumer level. Profits will reflect higher production costs of many key industries.

- The effect on financial markets. Financial markets, especially the bond and money markets, respond to the change in inflation. The effects of these changes will be determined by whether, and to what extent, Federal Reserve policy is altered.

- The effect on productivity. Perhaps the most important factor, the impact on productivity will depend on several responses, including the impact of carbon tax increases on the level of saving and investment, the mix between investment designed to conserve energy and investment that might have a larger impact on productivity, and the shifts in the composition of economic activity.

- The effect on U.S. competitiveness. The increase in production costs of energy-sensitive industries caused by higher energy prices; the degree to which costs rise in other countries; and the effect of interest rate changes and other factors on exchange rates will all determine the impact on U.S. competitiveness.

These impacts will then work through the economy altering consumer demand, new investment, trade flows, etc., which, in turn, will bring about changes in output, jobs, and income. In addition, spillovers and multiplier effects will develop. Ultimately, when all of the adjustments take place, a new level of economic activity, and a new trend rate of economic growth, will be reached.

Why Do the Models Vary?

Dozens of quantitative estimates assessing the impact of proposals to reduce CO_2 emissions are now available. All of these estimates have been made with econometric models which, to varying degrees, incorporate variables that measure key aspects and sectors of the economy, and behavioral relationships designed to capture the cause and effect relationships between them. Three types of econometric models have been used in the global warming studies: computable general equilibrium (CGE) models, standard macroeconometric models, and energy-based models.

CGE models generally attempt to determine how price changes will impact the demand and supply for various goods and services, and based on these relationships, the price levels that would result in market clearing. All of these models assume profit maximization by producers, and that consumers maximize their welfare based on some assumed relationship between welfare and present and future consumption. Implied in CGE models is the assumption that individuals and firms respond in an efficient manner to policy actions, and usually, that these responses occur relatively quickly. Unfortunately, these and other simplifying assumptions are probably not realistic over relatively long periods, let alone in the short term. However, short to intermediate term economic effects are perhaps the most important in evaluating different climate protection proposals, both because they are potentially very large and because such effects may reduce political support for continuation of these measures. It is thus not surprising that some, although not all, of the relatively optimistic studies are based on simulations of CGE models.

Macroeconometric models are designed to estimate the **actual** elasticities and sensitivities that underlie economic behavior (unlike CGE models, which frequently assume them), using standard estimation techniques applied to historical data. When used to simulate the impact of policy changes, these models theoretically can depict the actual adjustments that will take place, and the timing of such adjustments.

Standard macroeconometric models are thus more reliable in measuring the short term effects, but nonetheless also contain the potential for sizable predictive errors. This largely reflects such problems as the inability to develop quantitative measures for certain aspects of economic behavior, measurement errors in economic statistics, the limited power of the estimation techniques (which prevent them from perfectly separating the simultaneous influence of many factors), etc., which skew estimates of the key elasticities. These problems can not only undermine their model reliability, but often can cause two models to generate dramatically opposite results.

Finally, the energy-based models used in many of the global warming studies focus on the technological and other changes that are likely in response to energy tax increases, and the likely fuel substitution and other adjustments in various sectors of the economy that are implemented to reduce energy consumption. These technology-based energy models are perhaps the most flawed of all, because the assumptions embodied in them regarding the development of new energy-saving technologies or new energy sources cannot be known with any precision, and because they generally ignore important factors that prevent or delay the implementation of new energy-saving techniques (such as lack of information, high capital costs, risk avoidance, retrofitting, etc.).

The range of predictions of the economic effects of policy actions to reduce greenhouse gas emissions is large, in part because different types of models generally produce different results, and in part because of differences in the structure of models of the same general type. For example, the behavioral relationships within standard macroeconometric models can vary significantly because the models may have been estimated over different historical ti periods, using different data sources and variables, and with different estimati techniques. These factors can cause significant differences in the key coefficier or elasticities from one model to the next. In fact, it is very possible that relationships among some variables may be completely absent in one model, yet may be very significant in another. Thus, no econometric model perfectly captures the structure of the economy of the historical period for which it is estimated. Furthermore, the economy's structure may change, either because of changes in the relationships between some variables, or because new factors may emerge during the forecast or simulation period, both of which can also cause large forecast or simulation errors.

The large variation in the range of predictions among the global warming studies also reflects another factor – significant differences in the key assumptions that underlie the simulations. All models contain what are called exogenous variables – factors which measure some aspects of the economy, and which impact other variables embodied in the model, but which themselves are not forecast by the model. Judgments regarding the future of these variables must be made (assumed) before the model can forecast future trends, or simulate the potential impact of any policy change in the future. Generally, these variables are those which are determined by the political process, or for which factors cannot be identified or measured to explain their movement over time.

In the global warming studies, the key assumptions include whether the energy tax increases assumed are recycled back into the economy with offsetting tax cuts; the type of tax cuts assumed; etc. Two models with the exact same structure might forecast different responses to any given global warming proposal because they may be driven by different assumptions made on these and other key exogenous variables.

Why Do Models Underestimate the Economic Cost of Climate Protection?

There is really no way of knowing with any degree of certainty what the transitional and long term costs to the U.S. economy would be from major policy actions designed to reduce CO_2 emissions. The wide range of predictions among available studies is indicative of this uncertainty. However, some of the studies show little, if any, negative impact from energy taxes designed to limit greenhouse gas emissions. ESI believes that several favorable assumptions, and major model omissions, are causing a huge potential understatement of these economic costs in many available studies, even those which do indicate significant effects. These include the following:

- Size of the energy tax increase. As indicated earlier, all of the model simulations begin with an assumption regarding the size of the carbor tax increase that would be needed to reduce CO_2 emissions to a desired level. These assumptions are largely based on elasticities of energy demand, incorporating several estimated responses that are likely to occur if carbon taxes are raised, such as fuel substitution, pure conservation, and the development of alternative fuel sources. However, recent experience has underscored the difficulty of developing new energy sources and technologies which can compete with, and partially displace, fossil fuels within a reasonable period of time (nuclear energy is a case in point). Furthermore, much of the easy energy savings by consumers and businesses occurred in the 1970s and early 1980s. Investments needed to improve fuel efficiency further, will have to be even larger than in the past. This efficiency enhancing investment will divert funds from other uses, dampening productivity growth and/or reducing capacity expansion in many industries.

  Thus, even higher energy prices may be needed to reduce fossil fuel consumption and emissions to desired levels than the general assumption of $100 per ton of carbon. Several other considerations reinforce this conclusion. First, energy prices have in general been very subdued in recent years, after the oil price shocks of the 1970s. Spending patterns and investments may have been re-adjusted to thi era of lower energy prices, and relatively large price increases ma now be required to produce meaningful shifts back toward energy conservation. Second, many economic entities may assume that the tax increases will be reversed by future administrations and Congresses, limiting the response to a tax hike even further. Finally, a substantial amount of relatively new equipment is years away from being fully depreciated, and recent purchases of autos, household appliances, and other consumer durables have years of service ahead of them. Encouraging businesses and consumers to replace this equipment much earlier than planned will be difficult. These considerations imply a relatively modest and drawn out improvement in energy efficiency is likely and suggest that a sizable slowdown in economic growth will be needed to meet ambitious emissions targets.

- Revenue recycling. Many simulations assume that higher energy taxes will be recycled back into the economy dollar for dollar through tax cuts, making these levies revenue neutral. It is also assumed that offsetting tax cuts will favor savings and investment, over consumption. Because policies stimulating savings and investmen produce higher growth rates in these models, such assumptions bi economic costs estimates downward. It is not clear, however, that taxes will be cut; they may be used to pay for the burgeoning costs of the health care and other federal entitlement programs that will occur as baby boomer retire. Even if taxes are reduced, it is far from certain that the political will exists to reduce them in a way that stimulates savings and investment. It is more likely that any offsetting tax cuts will be designed to restore some or all of the squeeze on consumer income and purchasing power caused by tax-related increases in energy costs. In any case, these models generally overstate the response of saving and investment to tax incentives. As we saw clearly in the 1980s, the effect of so-called supply-side tax cuts on the levels of saving and investment is very low. Thus, the stimulus to economic growth from such tax cuts is likely to be considerably less than many models are forecasting.

- Announcement effect. Several studies assume that merely announcing an agreement to reduce emissions will encourage consumers and businesses to improve energy efficiency, thereby reducing the potentially adverse tax-related economic effects. However, there is absolutely no evidence that this will occur, nor any acceptable historical precedent.

- Benefits. Many studies have factored in sizable economic benefits from the assumed reduction in energy use and the slowing of the global warming process. These benefits include a reduction in health care costs because of cleaner air, higher crop yields, and more stable weather patterns. These benefits are generally super-imposed on the model results, with very little empirical support. Though there will be some benefits, history has shown that they could take decades to appear, and are likely to occur well after the negative impact of global-warming related tax increases is felt.

- Other countries. Some studies assumed joint implementation, which would allow the so-called Annex I countries to acquire emissions credits for helping underdeveloped countries to curb their energy consumption. Obviously, such an assumption lowers the estimated costs to the U.S. economy because it spreads the burden of reducing CO_2 emissions across more countries, and mitigates the adverse effects on U.S. competitiveness. However, it is far from clear that such an arrangement is workable, let alone effective. Thus, there is a clear downside risk in this assumption, with very little on the up side.

- Production shifting. Optimistic predictions, in particular, fail to address the effect of energy tax increases on U.S. competitiveness, or, if they do, understate such effects. However, as will be seen in Chapters V and VI, production costs in many U.S. industries will rise substantially, putting those industries at a huge competitive disadvantage. This is likely to have a drastic effect on U.S. trade flows. Moreover, greater mobility of capital and technology in recent decades, and the proliferation of developing country policies that demand investment as a prerequisite for market access, are likely to lead to significant shifts in production to locations outside the United States.

- Interest rates. Most of the model simulations that predict slightly negative, or even positive, impacts from higher energy taxes in the long run, also expect significantly lower real interest rates in the future. This results from a direct assumption that the Federal Reserve will ease monetary policy, and/or from interest rate equations within these models that predict a decline in long term and money market rates. However, both are highly questionable. First, energy tax increases will significantly increase the overall rate of inflation, at least in the short to intermediate term – the amount of added inflation will depend on the size of the tax increase, the time period over which it is phased in, and possible spillovers into wages and other prices. It is unlikely that real, market-based, interest rates would decline und these conditions, at least until markets can determine the amount of added inflation that would occur. Second, the Federal Reserve likely will raise interest rates to prevent inflation from spiraling out of as it did after the oil shock in the early 1970s. Furthermore, a strong case can be made that the U.S. economy is more sensitive to nominal and real interest rates than in the past because of the increased use of variable rate mortgages. Now, when interest rates rise, these mortgages (which now account for almost 50 percent of all home mortgages) are re-priced upward, which raises monthly payments, squeezes discretionary purchasing power, and reduces consumer spending. Thus, consumers could experience a double whammy if energy taxes are raised substantially: purchasing power would be squeezed both by higher costs for energy and other goods and services, and by higher mortgage rates. In short,, if real interest rates do not decline as much as forecast, the effect on the economy would be far larger than the optimistic scenarios are currently suggesting.

Regulation versus price impact. Virtually all the economic impact studie assume the imposition of a carbon tax in order to permit mode'

However, mandated industry emissions targets or other regulations could also be used to reduce U.S. energy consumption. Because command-and control-solutions are generally less efficient than market-based solutions, models based on a carbon tax are really depicting a best case scenario, because at least some regulatory solutions are likely to be imposed.

The Administration's Analysis – a Reality Check

The administration is on record as supporting strong measures to reduce CO_2 emissions in the years ahead because of its assumption that global warming is a serious environmental issue that must be addressed as soon as possible. As part of their efforts on this issue, the administration has formed an Interagency Analytical Team (IAT) to study the economic effects of global climate change policies. The task force used a group of economic models of the type discussed earlier to make these assessments, with the starting point that carbon taxes would be increased by about $100 per ton of carbon, which allegedly would lead to a reduction in greenhouse gas emissions in 2010 to 1990 levels.

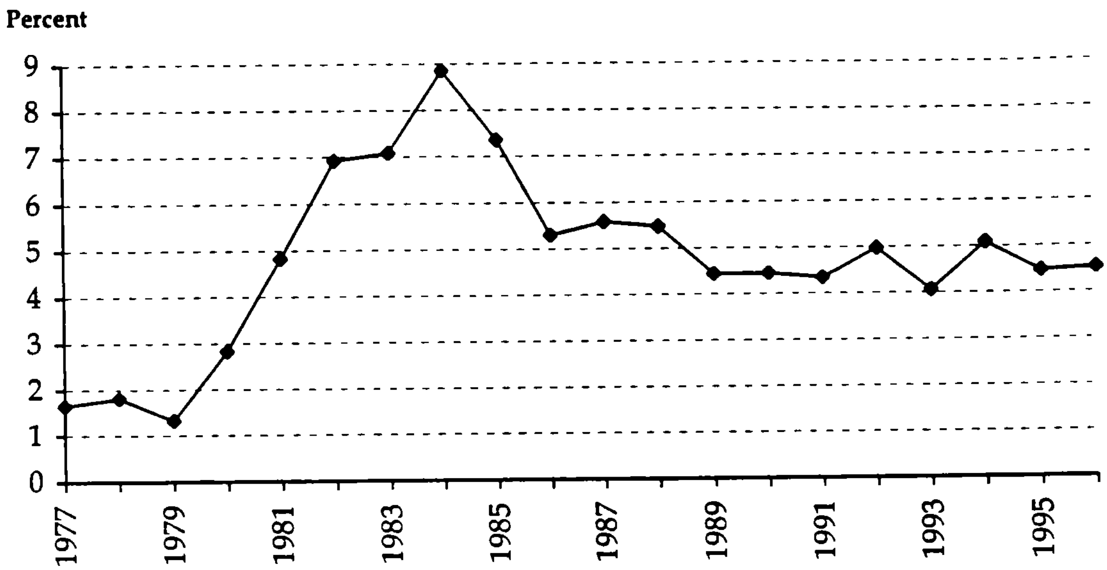
The simulations commissioned by the IAT essentially predict that only a very small loss in the level of economic output (less than 1 percent) would occur within the first ten years after the tax increases are enacted, and that output will then return to the assumed base case, or to even higher levels, within a few years thereafter. In addition, their results indicate that the use of cross border trading of emissions rights could prevent most of these very modest transitional economic losses.

However, there are several major flaws in the administration analysis, most of which, as discussed earlier, also account for the likely understatement of the economic costs in many of the published studies. These include the following:

- The IAT simulations include the assumption that the announcement of an agreement among countries to reduce CO_2 emissions will by itself produce a 25 percent increase in the rate of improvement in energy efficiency, based on the assumption that consumers and businesses will respond immediately to the prospect of higher carbon taxes, or a carbon permit fee, by adjusting their spending and capital decisions even before these fees are implemented. This is highly questionable at best and, while the administration did not provide simulation results without such an assumption, it is clear that the negative impact on jobs, income, and output would be considerably larger. The announcement effect is also supposed to encourage a speed-up in R&D to expand the search for new energy-related technologies, again a dubious assumption.

- The IAT simulations factor in a two hundred basis point decline in real long term interest rates, to almost 2 percent, level, a unseen in many decades (see exhibit IV.2). This is a heroic assumption, because, iL anything, new taxes and cost increases that threaten to push up the rate of inflation frequently raise real interest rates.

Exhibit IV.2
Real Long-Term U.S. Interest Rates, 1977-1996



Source: Economic Report of the President 1997

- The IAT also included benefits from reducing target emission levels through non-carbon emission reductions. The administration task force study indicates that taking into account the costs associated with such reductions would increase the economic impact by at least 25 percent, but this was not factored into the simulations.

- The auctionable, tradable permit system assumed in some of the simulations did not include an estimate of the potentially large costs associated with the development, implementation, and monitoring of the program.

While these are the most grievous sources of understatement, the IAT analysis suffers from other shortcomings. It does not take into account the adverse effects on U.S. competitiveness and potential shifting of production by producers in the United States; the drag on productivity of a likely shift in the mix of investmer spending toward energy conservation and away from more productive uses;

the incorporation of tax offsets which supposedly will accelerate economic growth by stimulating savings and investment.

A recent simulation made with the WEFA model, one of the oldest and most respected macroeconomic models now in use, illustrates how much greater the economic cost could be if more realistic assumptions are used. The WEFA simulation results indicate that:

- A carbon tax of $200 per metric ton would be required to meet the 2010 emissions target.
- This would raise gasoline prices by nearly $0.50 per gallon.
- Home energy costs would rise by more than $1,200 each year.
- U.S. GDP would decline by $228 billion (more than 2.5 percent) from the base case forecast.
- GDP would remain substantially below the base case for at least 25 years after the enactment of the tax.
- million jobs would be lost.
- The U.S. trade deficit would jump sharply.
- The growth in real income over an extended period would fall by 15 percent.

In short, by assumption and by omission, the administration's analysis biases the results towards minimizing the economic costs in both the short and long term. In fact, with more realistic assumptions, a simulation with one of the models used in the administration analysis shows much more severe economic impacts that are in line with the results of the WEFA study.

The 1970s Experience

It is thus increasingly clear that the economic costs associated with climate protection could be very substantial, far greater than the estimates that are currently available. These conclusions are reinforced by an examination of U.S. and global economic performance following the oil shocks of the 1970's. For example, the large oil price increases following the embargo in the early 1970s produced one of the deepest recessions in the United States since World War II (see exhibit IV.3).

Exhibit IV.3

Postwar Recessions

Peak-to-Trough Declines in Real Chain-Weighted GDP

Recession Period	Percent Decline in GDP
1969-70	0.7
1974-75	3.1
1980	2.5
1981-82	3.0
1990-91	2.0

Furthermore, average economic growth in the United States since 1973 has l about a percentage point lower than it was in the prior 13 years (see exhibit [illegible]). This accumulates to a difference of about 20 percent in the level of real GDP by the end of 1989, relative to the level which would have occurred if the historical growth rate had continued. The slowdown in the rate of increase in industrial production was even larger. And much of the differential in growth reflects differences in the rate of increase in productivity, and not simply population or other demographic factors. While it is clear that not all of this decline in growth can be attributed to the energy price shocks, it does call into question those studies that suggest that the maximum impact on the <u>level</u> of GDP after extremely large carbon tax increases would be on the order of 1 percent or less.

It is also worth noting that both productivity growth and overall economic growth decelerated dramatically in most other industrialized countries as well after the huge spike in oil prices in the 1970s (see exhibit IV.4). Again, while this is not conclusive by itself, it does suggest that the "not to worry" attitude, based on currently available studies of the economic effects of global warming measures, can result in a sense of complacency that will be harmful to I economic interests.

Exhibit IV.4
Average Growth Rates of Real GDP
1960-1973 and 1973-1989

	1960-1973	1973-1989
United States	3.95%	2.42%
European Union	4.68%	2.27%
OECD	4.82%	2.63%
OECD Europe	4.67%	2.31%
Japan	9.57%	3.84%

Note: EU, OECD and OECD Europe refer to 1991 membership

Source: OECD

Quite the opposite, these carbon tax increases are likely to cause a sizable recession and/or dramatically slow economic growth over a relatively long period of time, put U.S. industry at a significant competitive disadvantage in world markets, push up the trade deficit, lower living standards, and raise unemployment. This is reinforced by the fact that the increases in energy prices that are likely in the years ahead in response to carbon tax appears relatively close to those which occurred in the 1970s and early 1980s (see exhibit IV.5)

Exhibit IV.5
Changes in Real U.S. Prices of Various Energy Sources, 1973-1987
Versus Expected Changes Due to a Carbon Tax

	1973-1987	1994-2010
Oil	67%	70%
Natural Gas	223%	45%
Coal	24%	198%

Sources: Derived from data in Gary W. Yohe, *Climate Change Policies, Living Standards, and Real Wage Growth*; Argonne National Laboratory, *The Impact of High Energy Price Scenarios on Energy Intensive Sectors: Perspectives from Industry Workshops*; and ESI Calculations.

Chapter V: Impact of a Potential Carbon Tax on the Chemical and Steel Industries

This chapter examines the impact of a potential carbon tax on the chemical and steel industries. Both sectors are big users of energy, consuming more energy per unit of output than all other manufacturing industries on average. That being the case, any increase in fuel prices brought about by a carbon tax or its equivalent would significantly raise their manufacturing costs, leading to higher-priced outputs. Because the outputs of these industries are key intermediate inputs in other industries, manufacturing costs for a host of products would rise as well. The ripple effect would have profound implications for the international competitiveness of the United States, especially if similar measures are not undertaken by developing countries.

Chemicals

The chemical industry (SIC 28) is one of the United States' most important and competitive manufacturing industries. In 1995, it logged $362 billion in shipments, employed almost 840,000 individuals, and recorded a trade surplus of $21 billion (see exhibit V.1).

The industry is also a major user of energy. According to the Chemical Manufacturers Association, energy expenditures in 1995 totaled $26 billion.[28] Considering that producers in the United States face strong competition from producers in both developed and developing countries, it is clear that a carbon tax would have an adverse impact on the U.S. industry's output and competitiveness.

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[28] Swift, 4.

Exhibit V.1
Output, Employment and Trade of the U.S. Chemical Industry, 1995

	Units	Chemicals	Share of Total Manufacturing
Output			
Shipments	$ bil.	362	10.1%
Value added	$ bil.	196	11.5%
Employees	thou.	839	4.5%
Trade			
Exports	$bil.	59	12.1%
Imports	$bil.	38	6.1%
Balance	$bil.	21	NA

Sources: Bureau of the Census, and International Trade Administration

Energy Use Issues

Treatment of Feedstock

The chemical industry is an energy-intensive industry. Its energy intensity, 21,000 BTUs (British thermal units) per dollar of value added, is seventy-five percent higher than that of the manufacturing sector as a whole.[29] In addition, chemical producers use fossil fuels as a raw material (feedstock). Of the $26 billion spent on energy in 1995, roughly half served as feedstock in the production process. Since feedstock is not burned, it is not an immediate source of carbon dioxide emissions. Thus, a carbon tax or any other carbon abatement measure that does not distinguish between feedstock and power uses of fossil fuels would essentially double the impact on the chemical industry's energy costs without appreciably reducing carbon emissions.

Few Cheap Alternatives Exist

A carbon tax is expected to reduce greenhouse gas emissions by raising energy prices for fossil fuels. Higher prices, in turn, would encourage firms and individuals to use less energy and to use cleaner fossil fuels. Chemical firms, for instance, would reduce their energy dependence by increasing production of less energy-intensive products, by developing new technologies that require less fossil fuel, or by switching to less carbon-intensive energy sources.

Neither of these remedies would be cheap, or easy. It is generally acknowledged that the marginal cost of improving energy efficiency rises as an economy becomes more energy efficient. That is, incremental increases in energy efficiency

[29] Energy Information Administration, *Manufacturing Consumption of Energy in 1991* (Washington, DC: U.S. Government Printing Office, December, 1994), 97.

become progressively more expensive to achieve. In fact, advocates of aggressive emissions reduction strategies argue that, because a high share of U.S. electricity is generated from coal-fired power plants, emissions reduction in the United States will be relatively inexpensive.

Although fuel switching may be an option for some utilities, its potential is limited for the U.S. chemical industry. Only about ten percent of the industry's energy needs are supplied by high carbon-content solid fuels, and reliance on energy from distillate and residual fuel oils has already been reduced by seventy-three percent since 1974. Natural gas, the cleanest burning fossil fuel, already accounts for sixty percent of chemical industry energy consumption (see exhibit V.2).

Exhibit V.2
U.S. Chemical Industry's Energy Consumption, by Fuel Source
1974 and 1990

	1974		1990	
	trillion BTUs	share	trillion BTUs	share
Distillate fuel oil	120	4.2%	13	0.5%
Residual fuel oil	165	5.8%	64	2.4%
LPG	3	0.1%	3	0.1%
Natural gas	1,635	57.6%	1,637	60.6%
Coal	205	7.2%	269	10.0%
Coal & breeze	6	0.2%	3	0.1%
Electricity	437	15.4%	485	18.0%
Other	266	9.4%	226	8.4%
Total	2,837	100.0%	2,700	100.0%

Source: Chemical Manufacturers Association

Change Will Take Time

The chemical industry would be able to make some adjustments to the rising fuel costs ushered in by a carbon tax, but those adjustments would take time. Higher energy prices would encourage companies to make energy-saving capital investments. Given the new energy price levels, firms would minimize production expenditures by substituting capital expenditures for energy expenditures. Since a chemical plant's economic life is ten to twenty-five years, and sunk costs are high, companies would be unlikely to abandon existing plants right away. Instead, they would choose to retrofit existing facilities and to adjust the level of employment until a new plant is built. Since retrofitting can not provide the energy efficiency of a new plant, the full impact of a carbon tax on energy usage and emissions would not be felt for twenty or more years. This suggests that the ten-to-fifteen-year targets envisioned by parties to the Convention on Climate Change are inappropriate for the chemical industry.

Competitiveness Issues

A Truly Global Industry

The chemical industry is one of the world's most fiercely contested sectors, with competitors in both advanced and developing countries. The United States is the largest national producer of chemicals, recording $362 billion in sales during 1995. Turnover was $255 billion in Japan and $120 billion in Germany during the same period, and the European Union, if considered as a whole, had sales of nearly $450 billion in 1995. Together, the United States, Japan, and the European Union were responsible for seventy-three percent of global chemical sales. Non-OECD chemical production is significant as well. Asia (excluding Japan), Latin America, and central and eastern European countries accounted for twenty percent of global turnover in 1995 (see exhibit V.3).[30] In this environment, it is clear that price increases induced by a carbon tax on U.S. and other OECD producers would alter the distribution of global production.[31]

Exhibit V.3
Global Chemical Sales, by Region, 1995

	Share	Value
Annex I	84%	1,234
European Union	32%	475
USA	25%	362
Japan	17%	250
Other Western Europe	2%	29
Central and Eastern Europe	4%	59
Other Annex 1	4%	59
Non-Annex I	16%	235
Asia	12%	177
Latin America	4%	59
Total	100%	1,471

Source: European Chemical Industry Council

The Relocation Decision

That the United States is a major chemical producer is no accident. The country possesses abundant human capital, competitive supplier industries, domestic

[30] *Facts and Figures – The European Chemical Industry in a Worldwide Perspective* (Brussels: European Chemical Industry Council, 1996), 7.

[31] Central and Eastern European countries are considered part of Annex I, but it is not yet clear that they will be forced to adhere to any targets coming out of Kyoto.

supplies of key raw materials, and high levels of domestic chemical demand. Low energy prices, therefore, are only a partial explanation for the U.S. industry's competitiveness. The industry has enough advantages to ensure its survival, even if carbon taxes are applied only on Annex I countries.

That being said, a carbon tax in Annex I countries would clearly damage the U.S. chemical industry's competitiveness, and would encourage manufacturers in the United States to locate a larger share of their facilities overseas. According to a study performed by Argonne National Laboratory, in the event of a carbon tax, energy prices faced by chemical manufacturers in the United States would increase substantially more than energy prices in Europe, in both relative and absolute terms.[32]

Producers in the United States also would be hurt vis-a-vis the developing world. There is already substantial non-Annex I production capable of reaping substantial price advantages from a carbon tax on developed countries.

Production shifting is made more likely by competitive dynamics within the industry. The chemical industry is dominated by multinational corporations. Foreign chemical manufacturers, primarily European, have a strong U.S. presence; United States chemical firms have global production networks as well. In 1994 (the latest year for which data is available), value added by foreign affiliates of U.S. multinational chemical manufacturers totaled $56 billion, almost fifty percent of the value added by their U.S. parents.[33] In short, both U.S. and foreign multinationals have the ability to expand their oversees facilities if conditions warrant.

Evidence suggests that location decisions by the chemical industry are, in part, determined by energy costs. Within the United States, for example, the production of energy-intensive chemical products has gravitated toward regions with natural gas production. As a result, chemical manufacturers' energy costs for natural gas and electricity are lower than the U.S. average.[34]

Such production shifting can also occur across countries. Production of energy-intensive chemicals, such as ethylene derivatives, has already begun gravitating toward the Middle East, where energy prices are even lower than they are in the United States. Because the location of chemical production is clearly sensitive to

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[32] Dan Steinmeyer, "The Chemical Industry in the USA - The Role of Energy and the Impact of Energy Price Increases," in Ronald J. Sutherland, ed., *The Impact of High Energy Price Scenarios on Energy Intensive Sectors: Perspectives from Industry Workshops* (Argonne, Illinois: Argonne National Laboratory, July 1997), CH-44-45.
[33] See Bureau of Economic Analysis, *U.S. Direct Investment Abroad - 1994 Benchmark Survey, Preliminary Results* (Washington, DC: U.S. Government Printing Office, January 1997).
[34] Steinmeyer, CH-37-38.

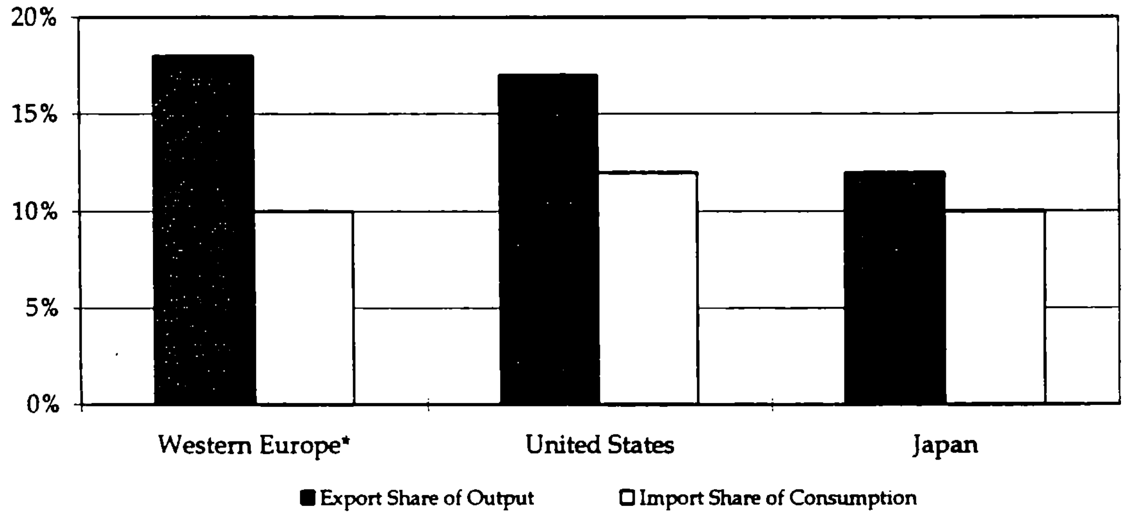
energy costs, an energy tax would cause more U.S. chemical manufacturers, over time, to relocate more of their manufacturing operations overseas than would otherwise be the case.

International Trade

The chemical industry has been a bright spot in the generally dismal U.S. trade picture. It is one of the few manufacturing sectors consistently producing trade surpluses. Yet, given the current competitive realities, it seems a foregone conclusion that a carbon tax affecting only Annex I countries would lead to a higher trade deficit for the U.S. chemical industry.

If measured in terms of import share, the U.S. market is the most open among major chemical producers. The United States has a higher import ratio than either Europe or Japan, and exports less of its output than does Europe (see exhibit V.4).

Exhibit V.4
Chemicals Trade of Western Europe, the United States, and Japan, 1995



Source: European Chemical Industry Council

Despite facing higher energy costs, the European industry is extremely competitive in international markets. E.U. exports to Asia (excluding Japan) reached $22.8 billion in 1995, $8 billion more than U.S. exports to the region. Europe also exported $1.5 billion more to Japan than did the United States. The U.S. industry, however, exported $4 billion more to Latin America than Europe did. Europe's performance is remarkable in light of the fact that its energy costs are significantly higher than U.S. costs (see exhibit V.5).

Exhibit V.5
Energy Prices Faced in Europe, Japan, and the United States, 1994

	Natural Gas*	Heavy Oil*	Coal*	Electricity**
United States	3.07	2.44	1.29	4.7
OECD Europe	4.03	3.37	3.68	7.5
Japan	12.3	4.46	1.69	17.3

*Dollars per million BTUs

**Cents per kilowatt hour

Source: International Energy Agency

European trade competitiveness is explained, in part, by lower labor costs. According to OECD statistics, labor costs in the E.U. chemical industry in 1995 were about twenty percent lower than they were in Japan and the United States. For their part, major producers in developing Asia and Latin America face substantially lower costs than do advanced country producers. In 1993, Korean labor costs in the industry were fifty-four percent lower than European costs, and Mexican costs were even lower.[35]

The impact on trade in U.S. chemicals would be large for two reasons. First, unlike production, trade is concentrated in energy-intensive products. U.S. chemical production is split roughly even between high energy-intensive products, such as inorganic and organic chemicals, plastics, and agricultural chemicals, and low energy-intensive products like pharmaceuticals (see exhibit V.6). European production is slightly weighted toward less energy-intensive goods.

[35] *Facts and Figures*, 54.

Exhibit V.6
U.S. and E.U. Product Mix, Ranked by Energy Intensity

	Energy Intensity*	U.S. Product Mix**	E.U. Product Mix
High Energy-Intensive Subsectors			
Inorganic chemicals	18%	7%	8%
Organic chemicals	12%	21%	15%
Plastic materials and synthetic resins	8%	17%	18%
Agricultural chemicals	8%	6%	5%
Total	NA	51%	46%
Low Energy-Intensive Subsectors			
Chemicals not elsewhere classified	4%	7%	12%
Soaps, detergents, cleaners, etc.	1%	14%	12%
Paints, varnishes and allied products	1%	5%	6%
Drugs	1%	23%	23%
Total	NA	49%	53%

*Energy Cost divided by value added; calculated with 1995 U.S. data.
**U.S. data is disaggregated on an SIC basis

Sources: U.S. Bureau of the Census, U.S. International Trade Administration, European Industry Council, and ESI estimates.

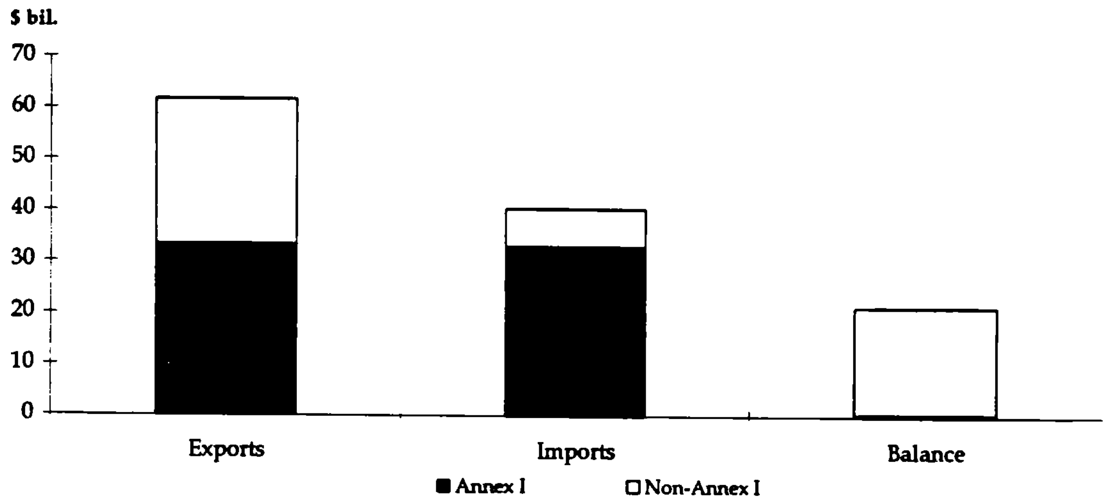
U.S. trade, on the other hand, is weighted in favor of high energy-intensive products. In 1995 and 1996, high energy-intensive chemicals accounted for seventy-one percent of U.S. chemical exports and sixty-five percent of chemical imports.[36] The two-year U.S. trade surplus in these products was $31 billion, which is equivalent to eighty-four percent of the combined chemicals trade surplus in 1995 and 1996. Because U.S. production costs for these products would be hardest hit by a carbon tax, the likely outcome of a tax would be to lower exports and raise imports in the one manufacturing sector where the United States currently runs a substantial trade surplus.

The geographic composition of U.S. trade flows also suggests that a carbon tax on Annex I countries would adversely affect the U.S. trade balance in chemicals. The U.S. chemicals industry registered only a small trade surplus of $0.43 billion with Annex I countries in 1995.[37] In contrast, the U.S. chemicals surplus with developing countries was $20.9 billion in that same year (see exhibit V.7). A carbon tax levied only on industrial countries would therefore have a much

[36] The chemicals trade figures in this paragraph are based on the 1987 SIC definition of the chemical industry. This allows for a direct comparison with the value-added and energy data needed to calculated U.S. energy intensities in the chemical industry.
[37] The chemicals trade figures in this paragraph are based on the SITC Rev. 3 definition.

larger impact on U.S. trade with developing countries than it would on U.S. trade with Annex I countries, and it would almost certainly result in a lower trade surplus with developing countries. The small surplus with Annex I countries could disappear, due to Europe's labor cost advantage in this industry and due to the lower expected increase in European natural gas prices.

Exhibit V.7
U.S. Chemicals Trade with Annex I and Non-Annex I Countries, 1995



Source: U.S. Bureau of the Census, Foreign Trade Division

Impact of a Carbon Tax on the Chemical Industry Output and Trade

In order to quantify the impact of a $100 per ton carbon tax on U.S. chemical industry output and trade flows by 2010, ESI used a partial equilibrium model based on the following assumptions:

- The 2010 GDP would decline 1.5 percent below baseline GDP. Most estimates predict a decline in the range of 0.5 to 1 percent, but those models assume that abatement policies would be phased-in beginning in 1990. The shorter phase-in period now being envisioned should result in a greater decline from baseline GDP than what has been predicted by earlier models. Moreover, as discussed in Chapter IV, several other factors have biased previous estimates downward as well. Thus, the 1.5 percent decline used here is conservative.
- There would be a $100 per ton carbon tax. Such a tax would result, on average, in a hundred percent increase in the energy prices faced by the U.S. chemical industry.
- There would be a carbon tax of similar magnitude for other Annex I countries. This is a simplifying assumption; fuel prices would likely rise more in Japan, less in Europe.

- Energy intensity would range from 3.5 percent of shipments (includes a feedstock exemption) to seven percent of shipments (no feedstock exemption).
- The price elasticity of demand would be minus 0.11. This is a weighted average of price elasticities for five major product categories.
- The income elasticity of demand would be 1.43. This is a weighted average of income elasticities for five major product categories.
- Export and import elasticities would be minus one and one, respectively.

The results, summarized below (exhibit V.8), imply a decline in output ranging from $16.1 to $22.3 billion, and a decline in the U.S. trade surplus ranging from $4.6 to $9.3 billion. On the trade front, the beneficiaries would be European producers, whose energy costs would rise less than U.S. energy costs, and producers in developing countries.

Exhibit V.8
Chemical Industry Output and Trade
Estimated Impact of a $100 per Ton Carbon Tax by 2010

	Base Case	Carbon Tax			
		With exemption		Without exemption	
		Value	*% change*	*Value*	*% change*
Domestic Demand	459.57	448.15	-2.5%	446.56	-2.8%
Shipments	487.32	471.26	-3.3%	465.04	-4.6%
Exports	79.15	76.31	-3.6%	73.47	-7.2%
Imports	51.40	53.20	3.5%	54.99	7.0%
Trade Balance	27.75	23.11	-16.7%	18.48	-33.4%
Exports as a Share of Output	16.24	16.19	-0.3%	15.80	-2.7%
Import Penetration	11.19	11.87	6.1%	12.31	10.1%

Source: ESI Estimates

Steel

The steel industry (SIC 331), despite falling on hard times during the early 1980s, remains an important and growing industry in the United States. Dismissed as an also-ran only a decade earlier, the industry shipped $74.6 billion of product in 1995 and employed 224,300 people. Though many experts consider the industry to be the low-cost producer for the U.S. market, imports continue to supply a significant portion of domestic demand, and the U.S. trade deficit in steel is about $10 billion (see exhibit V.9).

Exhibit V.9
Output, Employment and Trade of the U.S. Steel Industry, 1995

	Units	Steel	Share of Total Manufacturing
Output			
Shipments	$ bil.	75	2.1%
Value added	$ bil.	29	1.7%
Employees	thou.	224	1.2%
Trade			
Exports	$bil.	5	1.1%
Imports	$bil.	14	2.3%
Balance	$bil.	-9	NA

Sources: Bureau of the Census, and International Trade Administration

The steel industry has all the characteristics of an industry that would be hit hard by carbon abatement policies. Like chemical producers, steel makers are major energy users and face substantial competition from developing countries. One important difference between the two sectors is the steel industry's dependence on coal, the fossil fuel that will experience the largest price increase as a result of carbon abatement policies. Thus, the impact on the steel industry will be even more severe than on the chemical industry.

Energy Use Issues

Extremely Energy-Intensive Production

Steel production is one of the most energy-intensive manufacturing operations. In 1991, the latest year for which detailed energy consumption data is available, the industry required 108,000 BTUs per dollar of value added, nine times higher than the average for all U.S. manufacturing and five times higher than the chemical industry average.[38] Steel manufacturers also face substantial, indirect energy expenditures as well, due to the transportation requirements of both the traditional integrated mills and the newer minimills, which require large quantities of coal and scrap metal, respectively. This high level of energy dependence ensures that carbon abatement policies that rely on energy price hikes to reduce consumption would raise steel prices significantly.

[38] *Manufacturing Consumption of Energy in 1991*, 97.

Bifurcated Industry

The steel industry consists of two types of companies: integrated mills, which typically produce steel with "blast furnace/basic oxygen furnace" technology, and the so-called minimills, which produce steel with "electric arc furnace" technology and scrap metal. These technologies have different energy needs. Coal is the primary energy source of the integrated mills, while electricity is the main source of minimill power.

Because coal prices are expected to increase more than electricity prices in the event of a carbon tax, the energy prices faced by minimills should rise by less than those faced by the integrated companies. According to R.J. Fruehan's analysis for Argonne National Laboratory, the minimills' energy cost advantage, currently $10 per ton, could rise to more than $50 per ton by 2010.[39] Thus, carbon abatement policies that placed taxes or other restrictions only on advanced countries would not only favor foreign producers at the expense of domestic ones, but would also favor minimills over the integrated firms. However, the decline of integrated producers in the United States would result in higher prices for scrap steel, which would further hurt minimills' price competitiveness vis à vis producers in developing countries.[40]

Potential for Improvement Is Limited

The improvements in energy efficiency that carbon taxes are expected to promote will be hard to realize in the steel sector, for three reasons. First, as with chemicals, steel makers already have improved their energy efficiency dramatically. Consumption of energy has declined by forty-five percent during the past two decades, while value added has increased by seventy percent. Second, the potential for fuel switching within the industry is limited. Despite the increasing prominence of the minimills, coal remains the dominant source of energy in the industry (see exhibit V.10), and, unfortunately, there are few feasible alternatives to coal and coke in the steel making process. Technologies that rely on natural gas are available but, even if these are used, the resulting savings would still leave the integrated producers uncompetitive. Third, there are certain minimum energy requirements for certain steel making processes that, according to one expert, will be approached around 2010.[41] In short, dramatic improvements in steel industry energy efficiency are unlikely.

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[39] R. J. Fruehan, "The Effect of Increased Energy Prices on the Steel Industry," Ronald J. Sutherland, ed., *The Impact of High Energy Price Scenarios on Energy Intensive Sectors: Perspectives from Industry Workshops* (Argonne, Illinois: Argonne National Laboratory, July 1997), ST-38.
[40] Fruehan, ST-30.
[41] Freuhan, ST 30-34.

Exhibit V.10
U.S. Steel Industry's Energy Consumption By Fuel Source, 1991

	trillion BTUs	share
Natural gas	421	24.6%
Coal	841	49.1%
Coke & breeze	243	14.2%
Electricity	144	8.4%
Other	65	3.8%
Total	1,714	100.0%

Source: Department of Energy/Energy Information Agency

Competitiveness Issues

A Significant Developing-Country Presence

As in the chemical industry, both advanced and developing economies maintain steel industries with internationally competitive companies. However, the developing countries play a more important role in steel than they do in chemicals, in large measure because many developing-country governments view the development of a domestic steel industry as an important component of industrial policies to promote high value-added manufacturing. In 1995, the non-Annex I countries accounted for thirty-two percent of crude steel output and, in 1996, the Chinese steel industry replaced Japan's as the world's largest. The United States is the third largest national producer (see exhibit V.11).

Exhibit V.11
Global Production of Crude Steel, by Region, 1995

	Share	Value
Annex I	68%	501
European Union	21%	156
USA	13%	94
Japan	14%	102
Other Western Europe	2%	14
Eastern Europe & Former Soviet Union	15%	113
Other Annex 1	3%	24
Non-Annex I	32%	231
Asia	22%	163
Latin America	5%	35
Total	100%	732

Source: International Iron & Steel Institute, http://www.amm.com/ref/0123ch2.htm

Relocation Decision

The United States steel industry has been a net recipient of foreign investment. In other words, foreign steel manufacturers have invested more in the United States than U.S. steel makers have invested abroad. This pattern would likely be reversed if the burden of carbon dioxide reduction were to fall solely on the shoulders of advanced countries.

The U.S. steel industry historically has focused on serving demand in the U.S. market with domestic production. Export sales have been limited to less than ten percent of total shipments, one third of which typically go to Canada, and direct investment in foreign countries (FDI) has been miniscule. U.S. steel firms, therefore, are far less "multinational" than their counterparts in other U.S. manufacturing industries. In the chemical industry, for example, foreign affiliates of U.S. multinationals register forty-four cents in sales for every dollar in U.S. parent companies sales. For steel, that ratio is 0.06 to one. In contrast, foreign participation in the U.S. steel market is rather high. Foreign-owned manufacturers in the United States accounted for roughly twenty-five percent of industry-wide value added in 1995.

Because foreign companies operating in the United States are more internationalized than are their U.S. competitors, they would be able to shift production more quickly from their U.S. facilities to take advantage of price differentials arising from a discriminatory carbon tax. Moreover, they would likely choose developing-country locations for their future mills, in order to skirt the tax's competitive consequences. At the same time, U.S. steel firms would be more likely to invest overseas, particularly in non-Annex I countries. The bottom line: inward FDI would likely stagnate or reverse, while outward FDI would increase.

International Trade

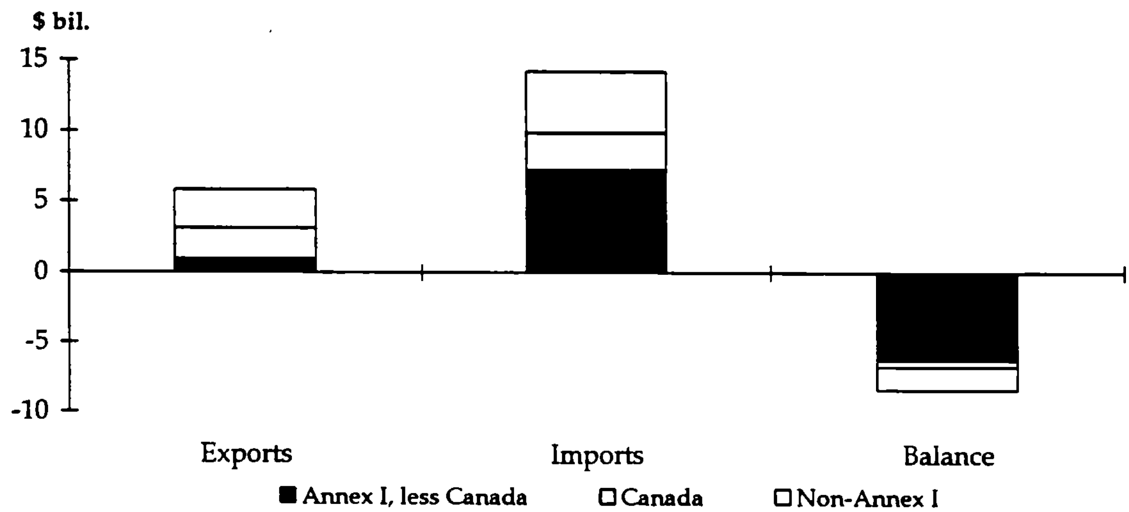
The United States remains a net importer of steel, but the picture has improved markedly since the mid-1980s, when import penetration in value terms approached twenty percent. Import penetration in 1995 was still a high seventeen percent and, with domestic capacity expected to increase in the near future, that figure is expected to remain relatively stable.

A steel industry burdened by a carbon tax would be an entirely different story, however. With energy prices faced by the industry likely to rise by more than a hundred percent, the impact on American steel's international competitiveness would be devastating, especially for the coal-reliant integrated mills. The integrated firms could either shut down entirely, leaving the field to imports and domestic minimills; abandon the most energy-intensive processes and import semi-finished product from developing countries; or invest in developing countries. Either way, U.S. value added and employment in the industry would decline. True, U.S. foreign direct investment in manufacturing tends to be "market seeking" and, more often than not, produces trade surpluses for the United States, but outward FDI resulting from a carbon tax would also be cost-driven and, thus, would enlarge the U.S. trade deficit in steel.

The composition of U.S. steel trade implies that a carbon tax would stifle U.S. competitiveness in developing countries, the very markets where U.S. exports are currently competitive. The United States does export more to Annex I countries, but most of this trade flows to Canada. If Canada is excluded from Annex I exports, U.S. steel exports are actually higher to the developing world than to other advanced countries (see exhibit V.12). The U.S. import market is currently dominated by Annex I product, but a carbon tax would tip the scales in favor of the developing countries. Brazil, Mexico, South Korea and South Africa, which currently export a combined $3.2 billion to the United States, as well as China, would be the big winners.

Exhibit V.12

U.S. Steel Trade with Annex I and Non-Annex I Countries, 1995



Source: U.S. Bureau of the Census, Foreign Trade Division

Impact of a Carbon Tax on Steel Industry Output and Trade

In order to quantify the impact of a $100 per ton carbon tax on the U.S. steel industry's output and trade flows by 2010, ESI used a partial equilibrium model based on many of the same assumptions used in analyzing the chemical industry. Differences include:

- The $100 per ton carbon tax would result, on average, in a 120 percent increase in the energy prices faced by the U.S. steel industry.
- The energy intensity would be fifteen percent of shipments.
- The price elasticity of demand would be minus 0.96. This is an average of various elasticities from two different studies.[42]
- The income elasticity of demand would be 1.035. This is an average of the high-end and low-end estimates of an industry study.[43]
- The import elasticity would be 0.94. This is taken from a recent ITC study.[44]

The results, summarized below (exhibit V.13), imply a $19 billion decline in U.S. industry shipments from base levels, a $3.7 billion dollar increase in the steel trade deficit, and a rise in import penetration, by value, to twenty-four percent. The integrated producers would bear the brunt of this adjustment, because the price of coal would rise more than the price of electricity, the minimills' main energy source.

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[42] See Stephen H. Karlson, "Modeling Location and Production: An Application to U.S. Fully Integrated Steel Plants," *The Review of Economic and Statistics* (1982); and John S. Hekman, "An Analysis of the Changing Location of Iron and Steel Production in the Twentieth Century," American Economic Review (March 1978).

[43] See Hekman, 124-132.

[44] Kenneth A. Reinert and Clinton R. Shields, *Estimated Elasticities of Substitution of a North American Free Trade Area*, U.S. ITC Staff Research Study No. 19 (Washington, DC: U.S. International Trade Commission), 29-41.

Exhibit V.13
Steel Industry Output and Trade
Estimated Impact of a $100 per Ton Carbon Tax by 2010

	Base Case		Carbon Tax			
	Value ($ Bil.)	*Mil. Metric tons*	*Value* ($ Bil.)	*% change*	*Mil. Metric tons*	*% change*
Domestic Demand	99.96	125.0	84.28	-15.7%	98.9	-21%
Shipments	88.3	105.0	69.0	-21.9%	73.0	-30%
Exports	6.3	7.6	5.1	-18.0%	5.6	-26%
Imports	17.9	27.6	20.4	14.3%	31.5	14%
Trade Balance	(11.6)	(20.0)	(15.3)	31.6%	(25.9)	30%
Exports as a Share of Output (Percent)	7.1	7.2	7.4	5.0%	7.7	7%
Import Penetration (Percent)	17.9	22.1	24.2	35.5%	31.9	44%

Source: ESI Estimates

Key Points

It is clear that both the chemical and steel industries would be hit hard by a carbon tax, especially if it were levied only on Annex I countries. The industries would no doubt survive, but they would survive with lower levels of output and, consequently, employment, and with more of their energy-intensive manufacturing processes occurring overseas.

The trade losses in both sectors would be concentrated in trade with developing countries, major export markets for both industries. The chemical trade surplus with non-Annex I countries, which accounts for nearly all the surplus in this sector, could decline by almost $9 billion if there is no feedstock exemption. In steel, the deficit with developing countries, currently much smaller than the deficit with Annex-I countries, would increase substantially.

Because competitors in Europe and Japan would also face energy price increases, the competitive impact among developed countries should be less dramatic. Prices of natural gas and coal, the primary energy sources for the chemical and steel industries, respectively, could be expected to rise less in Europe than in the United States or Japan, giving manufacturers in Europe a slight competitive advantage.

Moreover, those who expect a carbon tax to induce rapid gains in energy efficiency in these industries would be disappointed. Both sectors have already increased energy efficiency markedly since the mid-1970s through incremental technical innovations and, in the case of chemicals, through changes in product mix. Given higher marginal costs for future improvements, the long depreciation periods of these industries' capital stock, and the incremental nature of technical progress, rapid gains by 2010 are probably not achievable.

Chapter VI: Impact of a Carbon Tax on Autos, Air Transportation, and Semiconductors

The impact of a carbon tax would by no means be confined to the traditional smokestack manufacturers, such as chemicals and steel. Less energy-intensive manufacturers, and even service industries, would also be affected. This chapter examines the potential impact of such a tax on two of the less energy-intensive manufacturing industries, automobiles and semiconductor, and on air transportation services. The ripple effect of higher chemical and steel prices would be felt in these sectors, raising the cost of end-use products and services and thereby dampening demand.

Automobiles

The automobile industry (SIC 371), which employed 1.5 million people in 1995, is different from chemicals and steel in several ways. For instance, most of its output is sold directly to consumers, not to other industries. Moreover, the actual process of manufacturing a vehicle consumes little energy relative to chemicals and steel. Nevertheless, a carbon tax would have a substantial impact on this industry's costs, because it is a major consumer of energy-intensive intermediate goods, such as plastic, steel, and aluminum. Also, consumer demand for automobiles could be dramatically affected by the twenty-six-cent increase that a carbon tax is expected to add to the price of gasoline.

The industry's vital statistics are shown in exhibit VI.1.

Exhibit VI.1
Output, Employment and Trade of the U.S. Automobile Industry, 1995

	Units	Autos and Parts	Share of Total Manufacturing
Output			
Shipments	$ bil.	326	9.1%
Value added	$ bil.	105	6.2%
Employees	thou.	1,544	8.2%
Trade			
Exports	$bil.	50	10.2%
Imports	$bil.	105	16.8%
Balance	$bil.	(56)	NA

Sources: Bureau of the Census, and International Trade Administration

Energy Use Issues

Indirect Effect is Key

The car industry's energy intensity, the best measure of its direct energy usage, is well below the manufacturing average of 12,000 BTUs per dollar of value added. In 1991, the production of finished vehicles consumed 2,300 BTUs per dollar of value added. By itself, this low intensity suggests that manufacturing costs would barely be affected by a carbon tax.

Direct energy costs are only part of the picture, however. The cost impact of a carbon tax would be driven, in large measure, by rising costs of energy-intensive intermediate inputs. In fact, the automobile industry's importance to the U.S. economy stems largely from its role as a major purchaser of goods and services from other industries. For instance, in 1987, the last year for which detailed U.S. input and output (I-O) tables were published, the vehicle industry (SIC 3711, which excludes parts) purchased four dollars in inputs for every one dollar of value added, compared to a 0.79 ratio for U.S. industry as a whole. The parts industry (SIC 3713-5) purchased $1.62 in inputs per dollar of value added.[45] A large share of these inputs (e.g., plastics, aluminum, and steel) are energy intensive. As exhibit VI.2 shows, the direct impact of a doubling of energy prices on the value of vehicle shipments would be less than the indirect impact of higher energy costs on just a few major inputs.[46]

[45] See "Benchmark Input-Output Accounts for the U.S. Economy, 1987," *Survey of Current Business* (March 1994), 73-115.
[46] The indirect impact measured here only considers three commodities in addition to energy and, thus, understates the actual indirect impact of an energy tax on automobile industry costs.

Exhibit VI.2
Estimated Direct and Indirect Effects of a 100 Percent Increase in Energy Costs
Passenger Cars and Trucks (SIC 3711)

	Impact	Units
Rise in direct energy cost	1,132	$ million
Rise in cost of plastic, steel, and aluminum consumed directly by SIC 3711	129	$ million
Rise in cost of vehicle bodies, part, and accessories inputs (SIC 3713-5) due to consumption of energy, plastic, steel, and aluminum	1,345	$ million
Total	2,606	$ million
Memorandum:		
Total output of SIC 3711	134,115	$ million
Direct impact as a share of output	0.8	percent
Indirect impact as a share of output	1.10	percent

Sources: Bureau of Economic Analysis and ESI estimates

Behavior of End-Users Will Also Be Affected

A carbon tax would raise not only manufacturing costs, but also the cost of operating a vehicle. According to recent analyses by the administration and others, a $100 per ton carbon tax would translate into a gasoline tax of at least twenty-six cents per gallon. As exhibit VI.3 indicates, a tax of that magnitude would increase the cost of operating a vehicle by thirteen percent. The total price increase to consumers (operating costs plus depreciation plus other costs) would be about 5.5 percent.

Exhibit VI.3
Estimated Impact of a Carbon Tax on Operating and Ownership Costs

Per Mile* Cost of Ownership without a Tax ($)

	Gas & oil	Operating costs	Depreciation	Other	Total
Small	0.056	0.095	0.184	0.105	0.384
Mid-sized	0.066	0.108	0.218	0.121	0.447
Large	0.077	0.121	0.253	0.139	0.513
Light trucks	0.074	0.118	0.228	0.154	0.500

Per Mile* Cost of Ownership with a Tax ($)

	Gas & oil	Operating costs	Depreciation	Other	Total
Small	0.068	0.107	0.193	0.105	0.405
Mid-sized	0.080	0.122	0.229	0.121	0.472
Large	0.093	0.137	0.265	0.139	0.542
Light trucks	0.089	0.133	0.240	0.154	0.526

Cost of a Tax

	Gas & oil	Operating costs	Depreciation	Other	Total
Small	20.8%	12.3%	5.0%	0.0%	5.4%
Mid-sized	20.8%	12.7%	5.0%	0.0%	5.5%
Large	20.8%	13.2%	5.0%	0.0%	5.6%
Light trucks	20.8%	13.1%	5.0%	0.0%	5.4%

*Assumes that direct and indirect effects of higher energy costs on manufacturing costs raises automobile prices 5 percent above their baseline levels; based on 15,000 miles of driving per year.

Sources: Automobile Association of America and ESI estimates

It is naturally to be expected that consumers at the margin would respond to higher costs by driving less, by purchasing smaller cars and/or by postponing vehicle purchases. These behavioral changes would result in lower levels of output and employment in the industry.

Energy Efficiency Has Already Improved Substantially

As has been the case with chemicals and steel, the U.S. automobile industry has already taken major steps to increase energy efficiency and, by extension, to reduce carbon emissions. The figures are striking. Since 1974, the fuel economy of new cars has more than doubled, while light truck fuel economy has increased by fifty-five percent. In 1992, average fuel consumption per vehicle had dropped 106 gallons below 1975 levels. These gains were made possible, in large part, by technological improvements and by reductions in the length, weight and engine size of typical vehicles.

Further increases in fuel efficiency will result from additional technological breakthroughs, such as electric cars and other forms of low- and zero-emissions vehicles. Both U.S. and non-U.S. manufacturers already are making impressive strides toward bringing such products to market. Given this situation, it is unclear how a carbon tax, which would reduce available funds for investment in research and development, could hasten this beneficial development.

Competitiveness Issues

The Global Picture

The automobile industry is dominated by companies in advanced countries. In 1995, Annex-I countries produced eighty-one percent of all vehicles (see exhibit VI.4) The United States is the largest national producer, followed by Japan.

Developing-country industrial policies, foreign direct investment, and increased wealth in developing countries are causing increased production levels in non-Annex I countries. Though production in these countries is substantial, only cars from South Korea, Mexico, Malaysia, and Yugoslavia have made inroads into advanced-country markets.

Exhibit VI.4
Global Production of Automobiles, by Region, 1995

	Share	Units
Annex I	81%	43,046
Western Europe	30%	16,075
USA	22%	11,904
Canada	4%	2,391
Japan	19%	10,197
Eastern Europe & Former Soviet Union	4%	2,074
Other Annex 1	1%	405
Non-Annex I	19%	10,291
Asia	12%	6,353
Latin America	6%	3,062
Africa and Middle East	2%	877
Total	100%	53,338

Source: Automotive News 1997 *Market Data Book*

Relocation Decision

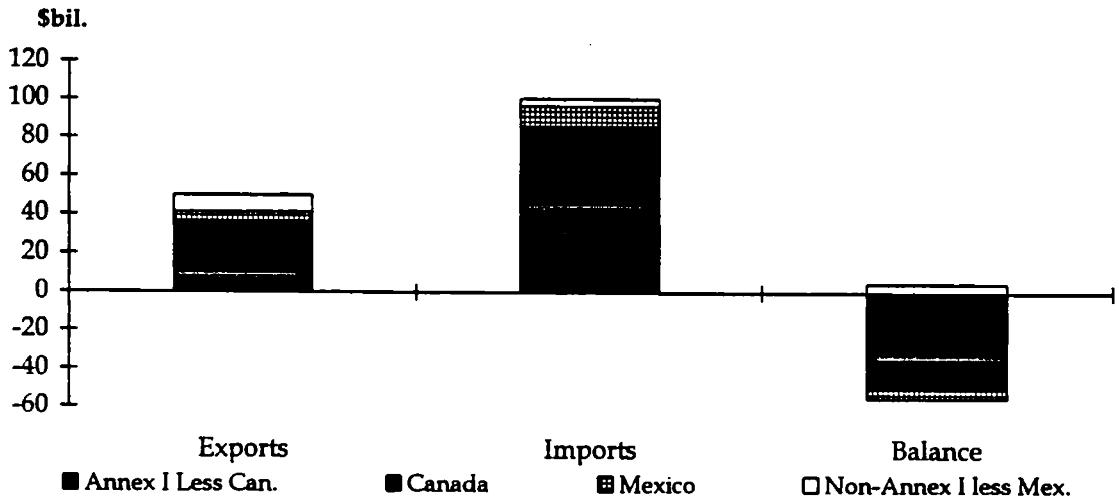
Annex I automobile companies have already made substantial investments in non-Annex I markets but, in most cases, production at these facilities is for the "local" market. Since final vehicle assembly in most advanced-country markets takes place in the country where cars are consumed, and because energy intensity of the assembly function is low, increased production shifting by vehicle makers, as opposed to parts makers, is unlikely.

Parts makers in the United States, however, face a different set of pressures, due to their greater consumption of energy-intensive inputs. Higher energy prices would likely increase the speed at which parts production would be localized in Mexico, especially for cars aimed at the local market. In order to remain competitive in Mexico, U.S. parts producers would likely be forced to increase their FDI there.

The need to remain competitive with parts made in other developing countries would also encourage U.S.-based parts makers to increase their FDI in developing countries. The main competition would come from Korea. Korean vehicle makers traditionally have relied heavily on foreign-made parts and components. In order to lessen this dependence, the Korean government is nurturing domestic parts producers with the aim of eventually becoming a net exporter of parts. A carbon tax that gave Korean producers a greater price advantage over parts makers in developed countries would do much to advance this goal, particularly in other non-Annex I markets. This price advantage would also help secure markets in the Annex I countries of Eastern Europe and the former Soviet Union, where Korean firms are investing heavily in automotive capacity.

International Trade
As illustrated in exhibit VI.5, U.S. automotive trade is dominated by Annex I countries. Canada plays an especially prominent role, both as an export market and an import source. The deficit with Canada would probably not change much in the event of a carbon tax, because the U.S. and Canadian industries are highly integrated.

Exhibit VI.5
U.S. Automotive Trade with Annex I and Non-Annex I Countries, 1995



Source: Bureau of the Census, Foreign Trade Division

On the other hand, the deficit with the rest of Annex I would probably rise. U.S. firms produce more of the larger, non-luxury cars and light trucks than do foreign nameplates. Sales of these larger vehicles would be hit harder by a carbon tax than would either small cars or luxury cars. Thus, sales of North American products should decline disproportionately more than sales of imported vehicles (see exhibit VI.6). Japanese and South Korean nameplates would benefit most from these changing preferences. Korean companies, of course, would also have the added competitive advantage of being located in a non-Annex I country.

Exhibit VI.6
U.S. Vehicle Market, by Size and Import Share, 1995

	Total Units Sold	Market Share	Import Share
Small	2,338,612	15.5%	22.0%
Mid-sized	4,190,978	27.7%	10.4%
Large	932,174	6.2%	0.0%
Luxury	1,173,234	7.8%	47.8%
Truck	6,481,357	42.9%	6.5%

Source: American Automobile Manufacturers Association

The FDI flows described above, as well as South Korea's price advantage borne of its non-Annex I status, would both tend to increase the U.S. deficit with non-Annex I countries. Because increased FDI to Mexico would be cost driven, parts exports would fall and imports would rise, adding to an already large automotive deficit with Mexico. The small surplus that the United States has with other developing countries, $4.7 billion in 1995, would likely become a deficit as U.S. exports to developing countries were replaced with local parts production, and competitive parts imports from South Korea and other developing countries expanded.

In sum, a carbon tax would hurt the competitiveness of U.S. motor vehicles vis à vis Japan, thereby increasing the already huge bilateral automotive deficit; expand imports from developing countries, especially from Mexico and Korea; reduce U.S. exports of parts and components to developing countries; and hurt U.S. parts manufacturers' chances of exporting to the markets of Eastern Europe and the former Soviet Union.

Impact of a Carbon Tax on Motor Vehicle Industry Output and Trade

Estimating the impact of a $100 per ton carbon tax on the vehicle industry is complicated by the fact that the impact of a carbon tax on both vehicle and gas prices would lead a significant number of people to purchase mid-size vehicles instead of light trucks. To get an idea of the potential impact that this forced change in preferences would have on U.S. output, ESI has illustrated the potential impact on U.S. vehicle output and trade if just ten percent of light truck purchasers opted to buy a mid-sized vehicle instead of a light truck.

The basic model has similar assumptions to those used in the models for the chemical and steel industries. Differences include:

- The $100 per ton carbon tax would translate into a $0.26 per gallon gasoline tax, about a twenty-one percent increase from current price levels.

- The compound growth rate of vehicle demand in the base scenario would be equal to 0.7 percent annually.

- A price elasticity of demand would be minus 0.25, because most of the substitution caused by higher prices occurs within the industry.

- The income elasticity of demand would be 1.08.[47]

- The import elasticity would be 0.98, taken from a recent ITC study.[48]

The results imply a six percent drop in shipped units, declining vehicle exports, a seven percent increase in import penetration, and a six percent increase in the trade deficit, in unit terms (see exhibit VI.7).

Exhibit VI.7
Motor Vehicle Industry Output and Trade
Estimated Impact of a $100 per Ton Carbon Tax by 2010

	Base Case	Carbon Tax	
Domestic Demand (Units)	16,783.36	16,280.7	-3.0%
Shipments (Units)	12,861.8	12,115.1	-5.8%
Exports (Units)	1,381.2	1,328.7	-3.8%
Imports (Units)	5,302.8	5,494.4	3.6%
Trade Balance (Units)	(3,921.6)	(4,165.6)	6.2%
Exports as a Share of Output (Percent)	10.7	11.0	2.1%
Import Penetration (Percent)	31.6	33.7	6.8%

Source: ESI Estimates

Though significant, these results actually understate the impact that the carbon tax would have on the U.S. auto industry. In dollar terms, the impact would be much larger for two reasons. First, the shift away from light trucks and large-sized passenger vehicles, which together account for more than half of U.S.

[47] Lawrence Horowitz, "The Impact of Carbon Taxes on Consumer Living Standards," in Charles E. Walker, ed., *An American Perspective on Climate Change Policies* (Washington, DC: American Council for Capital Formation, February 1996), 145.
[48] Kenneth A. Reinert and Clinton R. Shields, 29-41.

vehicle demand, would result in less per-car sales revenue for U.S. firms. Second, this shift would result in more imports, because the import share of the light-truck/large-car market is substantially lower than it is for mid-sized cars. Exhibit VI.8 illustrates this impact, based on a ten percent shift from light trucks and large vehicles to mid-sized cars, and assuming a $10,000 premium for larger cars. This shift would translate into higher imports, lower domestic production, and a $9 billion decline in U.S. revenue.

Exhibit VI.8
Potential Impact of a Shift in Vehicle Purchases toward Mid-Sized Cars

	Base case			
	Total (units)	Imports (units)	Domestic (units)	Domestic Revenue ($thou.)
Light trucks + large vehicles	8,694,498	463,222	8,231,276	230,475,729
Mid-sized vehicles	4,653,261	485,004	4,168,257	75,028,626
Total	13,347,760	948,227	12,399,533	305,504,355

	With 10 percent shift toward mid-sized cars			
	Total (units)	Imports (units)	Domestic (units)	Domestic Revenue ($thou.)
Light trucks + large vehicles	7,825,049	416,900	7,408,148	207,428,156
Mid-sized vehicles	5,522,711	575,626	4,947,085	89,047,531
Total	13,347,760	992,526	12,355,233	296,475,687

	Change from base case			
	Total (units)	Imports (units)	Domestic (units)	Domestic Revenue ($thou.)
Light trucks + large vehicles	(869,450)	(46,322)	(823,128)	(23,047,573)
Mid-sized vehicles	869,450	90,622	778,828	14,018,905
Total	-0-	44,300	(44,300)	(9,028,668)

Base case assumes a compound annual growth rate of 0.7 percent, import share in 2010 the same as in 1995, and per-vehicle revenue of $28,000 for light trucks and $18,000 for mid-sized cars.

Source: ESI estimates

Air Transportation

The airline industry (SIC 45) does not generally come to mind when one thinks of global climate change. Yet, the effects on this industry of a carbon tax, or other mitigation strategy that relies on higher energy prices, would, in many ways, parallel the effects on the automobile industry. The air transportation industry would be hurt not only by the general decline in aggregate demand that a tax would cause, but also by higher aircraft costs, higher fuel costs, and increases in other travel-related expenses, which would impact the frequency of travel in general.

The airline industry is a major employer, responsible for more than a million jobs in the U.S. alone. Its value added is also about seventy-five percent higher than the steel industry's value added (see exhibit VI.9)

Exhibit VI.9.
Output, Employment and Trade of the U.S. Airline Industry, 1995

	Units	Air Transportation Services	Share of Total Transportation Services
Output			
Value added*	$ bil.	51	22.9%
Employees	thou.	1,068	27.4%
Trade			
Exports	$bil.	19	17.4%
Imports	$bil.	14	16.3%
Balance	$bil.	5	NA

* Value added is for 1994.

Sources: Bureau of the Census, and International Trade Administration

Energy Use Issues

Direct Fuel Costs Are High

Though the air transportation industry does not manufacture anything, it is a major energy user. At 0.25 to one, its ratio of energy use to value added is about twice as high as that of the chemical industry. Furthermore, fuel costs make up twenty-to-thirty percent of the direct operating costs for most major airlines (see exhibit VI.10). Since direct operating costs typically account for thirty-to-forty percent of total airline costs, every ten percent rise in the price of fuel is accompanied by a subsequent one percent increase in total costs. Moreover, a carbon tax would come on top of the user fees that airlines already pay, and on top of the so-called ticket tax that was enacted as part of this year's budget accord.

Exhibit VI.10
Energy Expenditures as a Share of Direct Operating Costs, 1995

	Fuel Oil ($ bil.)	Fuel Costs as Share of Total Direct Operating Costs
Air Canada	328.7	30.5%
Air France	736.7	25.9%
Lufthansa	819.0	24.2%
JAL	1,303.2	28.1%
British Airways	943.1	29.0%
American	1,482.3	24.1%
Northwest	1,031.5	28.8%
United	1,583.5	24.4%

Source: ICAO

Indirect Energy Use Is Substantial As Well
Like the motor vehicle industry, the air transport industry also purchases energy-intensive products. Its major input, of course, is aircraft, and aircraft prices would be sure to rise if an energy tax were implemented, because their major material inputs include aluminum, steel, plastic, and rubber. Those inputs alone account for about seven percent of the value of aircraft shipments. Consequently, a fifteen percent rise in the price of those products would increase aircraft prices by about 1.1 percent. Also, the increase in direct energy costs to aircraft manufacturers would increase aircraft prices by another one percent. Given that prices for products such as metal working machinery and other capital equipment would rise as well, the total price effect of direct and indirect energy use would likely be in the neighborhood of four-to-five percent. Unless aircraft manufacturers replaced their domestic production with imports from non-Annex I countries, airlines would have to pay higher prices for their planes. The cost of these extra expenditures would ultimately be borne by consumers.

Higher Ticket Prices and Lower Incomes Would Mean Fewer Travelers
As in the case of automobiles, consumers affected by slowed income growth and by the higher prices resulting from a carbon tax would change their behavior. Specifically, travelers sensitive to shifts in price and income would either use less

costly forms of transportation, downsize their vacations by flying closer to ho put more effort into tracking down discounted flights, or choose not to trave all. As exhibit VI.11 indicates, fliers are especially sensitive to changes in income. For airline services, a one percent decline in income translates into a 1.63 percent decline in expenditures on air travel, over the long run.

Exhibit VI.11
Long-Term Income Elasticities for Selected Consumption Categories

	Income Elasticity
Airline service	1.63
Other durable goods	1.51
Furniture and appliances	1.28
Other non-durables	1.23
Motor vehicles and parts	1.08
Financial services	0.89
Clothing and shoes	0.86
Electricity	0.82
Natural gas	0.70
Medical services	0.61
Gasoline	0.60
Food and beverages	0.54
Telephone service	0.36
Housing	0.17

Source: DRI

Competitiveness Issues

The Global Picture

OECD countries dominate airline services, accounting for seventy-three percent of scheduled passenger kilometers worldwide (see exhibit VI.12). The United States, generally considered to have the most competitive airline services sector, is the largest national market within this group of countries. The market share of carriers based in the United States and other Annex I nations would likely be even higher if trade in airline services were as open as trade in goods. However, governments in both OECD and non-OECD countries closely regulate access to their domestic markets.

Exhibit VI.12
Global Scheduled Passenger Kilometers Performed, by Country, 1995

	Share	Passenger Kilometers Performed (millions)
OECD	73%	1,602.6
United States	39%	853.4
Germany	3%	62.2
France	3%	66.9
United Kingdom	7%	152.5
Japan	6%	130.0
Other	15%	337.6
Non-OECD	27%	607.1
China	2%	54.2
Singapore	2%	45.4
Russia	3%	61.0
Brazil	2%	34.3
Argentina	1%	11.9
Other	18%	400.3
Total	100%	2,209.7

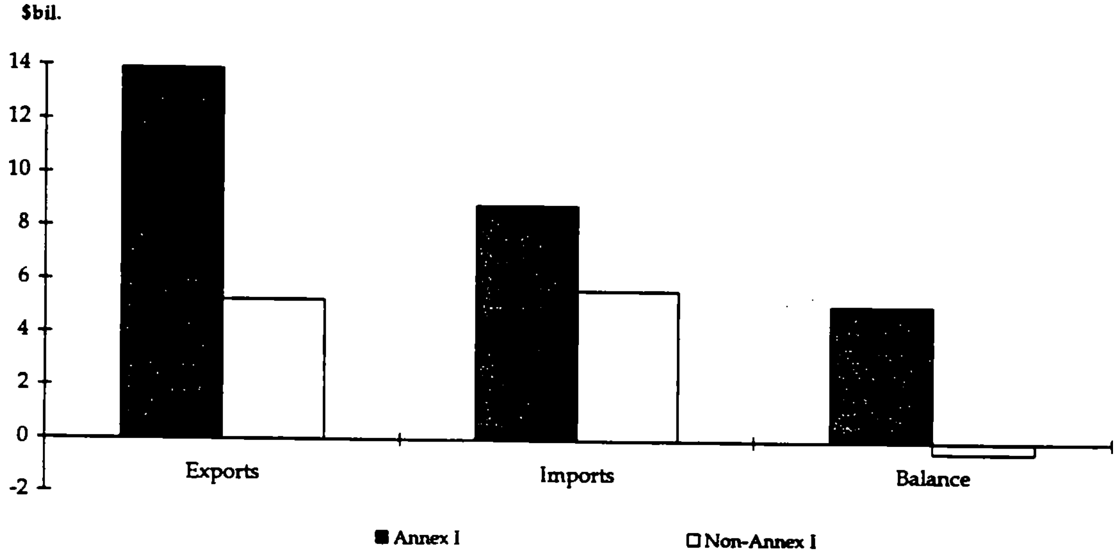
Source: International Civil Aviation Organization and ESI Calculations

International Trade

Unlike the industries previously covered, the competitiveness impact of a carbon tax would likely be slight in the case of the airline industry, especially if it is applied "at the pump." Most major competitors are from Annex I countries, and carriers from developing countries flying to and from the United States would likely have to purchase at least some of their fuel in the United States. Likewise, U.S. carriers flying to developing countries could purchase fuel for their return trips in the developing countries, thereby avoiding the tax on at least one leg of their journey.

A system could be devised, however, that would allow carriers from non-Annex I countries to receive a tax rebate on fuel purchased in developed countries. Under such a scenario, Annex I carriers, including those from the United States, would be at a competitive disadvantage and would likely lose international customers to developing-country airlines. The United States is already running a deficit in passenger airline services trade with developing countries, and this shortfall would likely expand if abatement policies were shouldered solely by advanced-country airlines (see exhibit VI.13 below)

Exhibit VI.13
Passenger Airline Services Trade with Annex I and Non-Annex I Countries, 1995



Source: Bureau of Economic Analysis

The competitiveness effect of a carbon tax on the U.S. airline services industry, therefore, would depend on how the tax was implemented. The impact of a tax without a rebate system would likely be small, but a tax that discriminated against Annex I countries would damage their carriers' competitiveness. Unfortunately, since price-sensitive international travelers would simply shift to non-Annex I carriers, the discriminatory tax would have no impact on energy consumption or, by extension, on global carbon emissions.

Impact of a Carbon Tax on Airline Services Industry Revenue and Trade

ESI has attempted to estimate the potential effects of a carbon tax on airline revenue, using a methodology and assumptions similar to those used for the previously discussed industries. Though current uncertainty surrounding the cross-border implementation of a carbon tax makes any effort to quantify its impact on trade purely speculative, ESI has also included a small trade effect. Assumptions specific to airline services include:

- A $100 per ton carbon tax would translate into a $0.34 per gallon increase in finished aviation fuel costs.
- Domestic demand for, and imports of, airline services would expand three percent per year through 2010 in the base scenario.
- Airline services exports would expand six percent per year, due to increased economic growth in, and travel to and from, developing countries.
- Price elasticity of demand would be minus one.
- Income elasticity of demand would be two.[49]
- Export and import elasticities would be minus one and one, respectively.

The results, shown in exhibit VI.14, imply a 6.5 percent revenue decline from the base scenario, driven primarily by a decline in domestic demand for airline services. The trade impact would be smaller than it would be in the other industries examined, but the U.S. airline services surplus would still decline 8.5 percent below baseline levels.

Exhibit VI.14
Airline Services Industry Revenue and Trade
Estimated Impact of a $100 per Ton Carbon Tax by 2010

	Base Case	Carbon Tax	
	Value	*Value*	*% Change*
Domestic Revenue ($ bil.)	140.0	131.4	-6.2%
Total Revenue ($ bil.)	163.4	152.8	-6.5%
Exports ($ bil.)	45.8	44.5	-3.0%
Imports ($ bil.)	22.5	23.1	2.8%
Trade Balance ($ bil.)	23.3	21.4	-8.5%
Export Receipts as a Share of Revenue (Percent)	28.1	29.1	3.8%
Import Penetration (Percent)	16.1	17.6	9.5%

Source: ESI Estimates

The impact of a decline in airline travel on the domestic economy would be much larger if a less efficient mechanism for reducing carbon emissions were employed. For instance, the Campbell Aviation Group has estimated that the direct, indirect, and induced effects of keeping the industry's fuel consumption at 1990 levels could have a negative economic impact on the United States amounting to $770 billion by 2010.

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[49] This elasticity is higher than the one in exhibit VI.11, reflecting the increasing sensitivity of air travel to income fluctuations.

Semiconductors

The semiconductor industry (SIC 3674), after almost succumbing to the onslaught of predatory Japanese dumping during the mid-1980s, has been a driving force in the high-technology revolution that has helped to remake the U.S. economy during the 1990s. Industry shipments in 1995 totaled $65.6 billion, a whopping 120 percent increase over 1991 shipments. Semiconductor manufacturers employed 193,400 people in high-value-added jobs in 1995. The value added per employee was a staggering $265,000 per person. However, despite obvious U.S. competitiveness in this sector, the United States ran a trade deficit of more than $16 billion (see exhibit VI.15).

Exhibit VI.15.
Output, Employment and Trade of the U.S. Semiconductor Industry, 1995

	Units	Semiconductors	Share of Total Manufacturing
Output			
Shipments	$ bil.	65.6	1.8%
Value added	$ bil.	51.3	3.0%
Employees	thou.	193.4	1.0%
Trade			
Exports	$bil.	22.4	4.6%
Imports	$bil.	38.9	6.2%
Balance	$bil.	(16.5)	NA

Sources: Bureau of the Census, and International Trade Administration

At first glance, the semiconductor industry does not seem to fit the profile of an industry that could be damaged by deliberations in Kyoto. It is certainly not a smokestack industry. Its expenditures on electricity in 1995 amounted to only 0.8 percent of value added. Rising production costs resulting from an energy tax, therefore, would have only a very small impact on the price of the average semiconductor.

In this case, however, first impressions are deceiving. Semiconductors are essential components in a wide and increasing range of consumer and capital goods. A drop in demand induced by an energy tax, therefore, would substantially affect semiconductor sales. Moreover, perflourocarbons (PFCs), manmade greenhouse gases that will be discussed at the Kyoto meeting in December, are an integral part of the semiconductor manufacturing process.

Energy Use Issues

Microprocessors Versus DRAMs
The industry's low energy intensity is somewhat misleading, because it lumps together different products having vastly different energy intensities. While energy costs, as a share of revenue, are low for high-margin products such as microprocessors, they are high for low-margin products such as dynamic random access memory chips (DRAMs). DRAM imports are already substantial, especially from developing-country producers, but some U.S. producers are extremely competitive, recording profits even though memory prices have declined precipitously during the past eighteen months. An energy tax applied only on Annex I countries would put U.S. DRAM manufacturers at a severe competitive disadvantage, perhaps completing the job begun by Japanese dumpers during the 1980s.

No Substitute for Perflourocarbons
Though the attention in Kyoto will be focused heavily on CO_2, PFC mitigation strategies likely will be a topic of discussion as well. Given the key role of PFCs in the manufacturing process, rushed and ill-conceived efforts to limit PFC use in Annex I countries would have a chilling effect on semiconductor manufacturing in the United States.

Perfluoroethane serves as a purging agent in the production of semiconductors. The process results in emissions of PFCs (gases usually associated with aluminum smelting) and sulfur hexafluoride. Because there are currently no substitutes for perfluoroethane in the manufacturing process, any usage limits, or taxes to produce an equivalent reduction, would raise domestic manufacturing costs dramatically. Obviously, such a development would give producers in non-Annex I countries a major advantage.

The U.S. semiconductor industry has been proactive in its efforts to reduce PFC emissions. Individual companies have signed a memorandum of understanding with the Environmental Protection Agency, committing them to work toward emissions reduction. SEMATECH and individual companies have undertaken major research efforts aimed at finding a commercially viable alternative to perfluoroethane.

Current and Past Developments Offer Long-Term Energy Savings Potential
The rapidly growing capabilities and falling prices among the semiconductor and other high-tech industries, such as computers and telecommunications, have led to increased consumption of these products. Concurrently, increased manufacturing activity in these sectors has led to higher levels of U.S. energy

consumption and, by extension, greater greenhouse gas emissions. On the other hand, these high-tech industries may actually lead to less energy consumption in the long run, as teleconferencing, telecommuting, and e-mail reduce energy consumption associated with travel and postal services. Efforts to harness high-tech industries through higher energy taxes, or other policies, risk a slowdown in the pace of technological change, thus delaying the advent of energy-saving technologies that would produce lower levels of greenhouse gas emissions in the long run.

Competitiveness Issues

The Global Picture

Annex I producers, particularly those based in the United States and Japan, account for the vast majority of global semiconductor sales. Producers based in other Asia-Pacific countries, such as South Korea, have made impressive strides during the 1990s, with market share tripling between 1990 and 1995 (see exhibit VI.16) Asia-Pacific producers are especially strong in DRAM production, and industrial policies in several countries throughout the region are aimed at developing indigenous semiconductor industries. The goal of Korean industrial policy is to shift the country's product mix away from DRAMs and toward microprocessors and other products currently produced in the United States.

Exhibit VI.16
Global Semiconductor Market Share, by Region of Capital Affiliation
1990 and 1995

	1990 (percent)	**1995** (percent)
Annex I	96.1	87.9
United States	38.6	39.8
Japan	46.3	39.5
Europe	11.2	8.6
Non-Annex I	3.9	12.1
Asia-Pacific (excl. Japan)	3.9	12.1

Source: ESI, *Prospects for U.S.-Japanese Semiconductor Trade in the 21st Century*

The Relocation Decision

Semiconductor manufacturers based in the United States, Japan, Europe and Korea have been active foreign investors. The U.S. market is home to Japanese, European, and Korean-owned firms, and U.S.-based firms have production outlets throughout the world. Though much of this cross-investment has been market seeking, cost-driven FDI has also occurred. Major producers long ago relocated low-value-added, labor-intensive functions to lower-wage countries. In short, the semiconductor industry is mobile and sensitive to cost differences across countries.

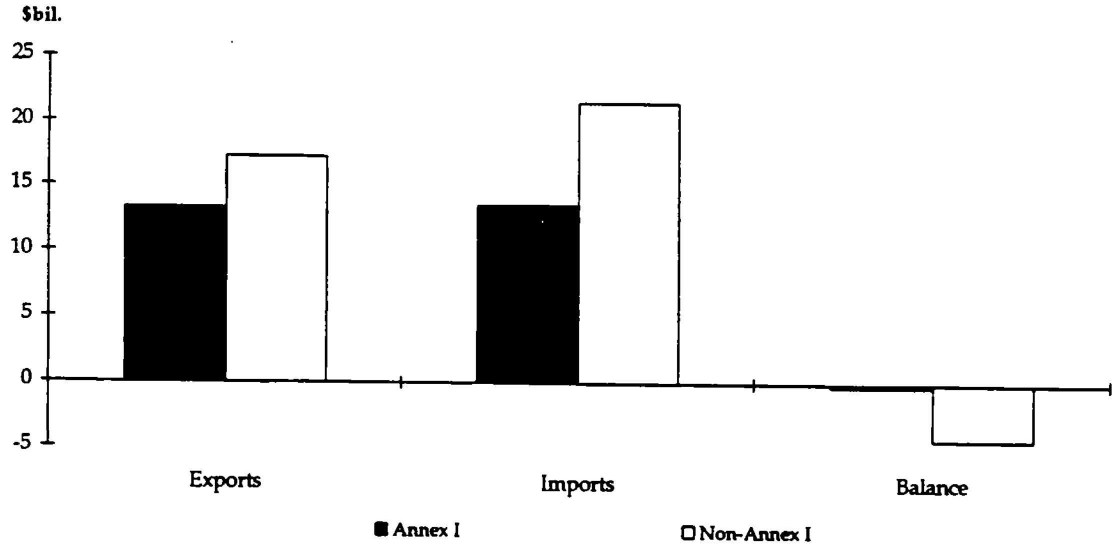
As a production site, the United States now has enough advantages to ensure a viable domestic industry, even in the face of energy taxes. Yet, a tax levied only on Annex I countries would provide a powerful incentive for Annex I producers to shift production of low-margin, energy-intensive products like DRAMs to countries exempted from a carbon-based energy tax. All other things being equal, a tax on Annex I countries would result in less FDI in the United States and more U.S. FDI in non-Annex I countries than would otherwise be the case.

International Trade

Despite its competitiveness, the United States is a net importer of semiconductors.[50] Japan is the largest national source of U.S. imports, followed by Korea, Malaysia, Taiwan, and Singapore - all non-Annex I countries. In fact, the majority of U.S. semiconductor imports come from non-Annex I countries (see exhibit VI.17).

[50] Statistics offer a somewhat confusing picture of semiconductor trade. According to the SIC-based trade numbers, the U.S. deficit in "semiconductors and related devices" was 16.5 percent in 1995. According to SITC-based trade statistics, the U.S. deficit in "integrated circuits" was only $4.5 billion in 1995. The country-by-country discussion in this section is based on SITC definitions.

Exhibit VI.17
U.S. Semiconductor Trade with Annex I and Non-Annex I Countries, 1995



Note: Trade figures based on SITC Rev. 3 classification
Source: Bureau of the Census, Foreign Trade Division

An energy tax on Annex I countries clearly would aggravate the U.S. trade shortfall, for three reasons. First, the change in FDI flows resulting from a carbon tax would lead to more production in non-Annex I countries and less production in the United States than would otherwise occur. Second, producers based in Korea and other developing countries would gain a cost advantage in DRAMs and other low-margin products, potentially rendering U.S. makers of these products uncompetitive. Third, the lower rise in European electricity prices would encourage U.S. producers to service a greater share of European demand with their production facilities on the continent. Because manufacturers in Japan and the United States are expected to face similar increases in electricity costs, the overall impact on competitiveness between the two should be relatively minor.

Furthermore, erosion of the U.S. balance of trade with developing countries would be magnified greatly if advanced countries were burdened by PFC restrictions. Such restrictions would make the addition of capacity in the United States nearly impossible and would compel U.S.-based makers to shift even more production to developing countries, in order to serve rapidly growing U.S. semiconductor demand. PFC policies that undercut U.S. competitiveness would be a boon to DRAM producers in Korea and Taiwan with high capacity levels. Because production would merely be shifting, this U.S. "sacrifice" would produce no net, global change in PFC emissions levels.

Impact of an Energy Tax on Semiconductor Industry Output and Trade

In addition to estimating the effect of a $100 carbon tax, ESI has attempted to capture the impact of restrictions or tax increases on PFCs. Assumptions for these estimates include:

- The $100 per ton carbon tax and PFC mitigation policies would translate into an average five percent increase in semiconductor prices.
- Domestic demand for semiconductors in the base scenario would rise seven percent per year from 1995 levels.
- Due to U.S. competitiveness in high-value-added product lines, U.S. semiconductor exports would rise seven percent per year, versus a five percent growth rate for imports.
- A low price elasticity of minus 0.2 would reflect the paucity of substitutes for semiconductors.
- A high income elasticity of 1.75 would reflect the high and growing semiconductor content of durable consumer and capital goods, which generally have higher than average elasticities.
- Export and import elasticities of minus 1.2 and 1.2, respectively, would be slightly higher than average, reflecting the fact that a high proportion of U.S. semiconductor trade would occur with developing countries and would be price sensitive.

The potential impact on the semiconductor industry of a combination of energy tax and PFC mitigation policies would be even larger, in percentage terms, than the impact on the auto industry (see exhibit VI.18). Shipments in 2010 would be down eight percent from base levels, while exports would fall six percent and imports would expand 5.8 percent. The trade deficit would be $8.4 billion higher than would otherwise be the case.

Exhibit VI.18
Semiconductor Industry Output and Trade
Estimated Impact of a $100 per Ton Carbon Tax and PFC Restrictions by 2010

	Base Case	Carbon Tax	
	Value	*Value*	*% change*
Domestic Demand ($ bil.)	226.7	218.5	-3.6%
Shipments ($ bil.)	207.5	191.0	-8.0%
Exports ($ bil.)	61.8	58.1	-6.0%
Imports ($ bil.)	80.9	85.6	5.8%
Trade Balance ($ bil.)	-19.1	-27.5	43.9%
Exports as a Share of Output (Percent)	29.8	30.4	2.1%
Import Penetration (Percent)	35.7	39.2	9.7%

Source: ESI Estimates

Key Points

The automobile, airline services, and semiconductor industries in the United States, like their smokestack brethren, can expect significant declines in output and competitiveness if U.S. negotiators agree to an energy tax aimed at constraining U.S. emissions to 1990 levels, especially if steps are not taken to constrain developing-country emissions. The potentially large impact on the automobile industry is not surprising, because the cutting of energy consumption due to automobile use is a major goal of proposals now on the table. The potentially large effects on airline services and semiconductors, however, is surprising, as well as alarming, because these industries have been considered to be the engines of a "new" U.S. economy driven by services and high-tech manufacturing. The bottom line? A carbon-based energy tax levied only on advanced countries would deal a very hard blow to just about all sectors of the U.S. economy.

Contrary to popular perceptions, U.S.-made autos and parts, like U.S.-made chemicals and steel, compete relatively well in developing-country markets, a situation that a carbon tax would almost certainly alter. By 2010, U.S. trade balances in the auto, airline, and semiconductor sectors would deteriorate sharply, driven mainly, but not exclusively, by trade with non-Annex I countries. Ironically, even the "new economy" sectors of airline services and semiconductors ran trade deficits with developing countries in 1995, and they would run even larger deficits by 2010 if a discriminatory energy tax were to become reality. Such developments could only poison American popular attitudes toward trade with developing countries, thus undercutting decade-long efforts to open those markets through bilateral and multilateral negotiations.

At present, promising efforts to reduce greenhouse gas emissions are ongoing in the auto and semiconductor industries. To penalize them with a tax on energy would hamstring those activities, because lower sales revenues and higher operating costs inevitably translate into less R&D expenditures. In this sense, many of the mitigation options aiming to shunt energy consumption back to 1990 levels by 2010 are misguided.

Chapter VII: Conclusions and Recommendations

In summary:

- Evidence that man-made greenhouse gases will raise temperatures significantly in the decades ahead is ambiguous. While computer models project such a trend, actual satellite data does not conform to the projections and indicates there has been little, if any, global warming since World War II even though most of the man-made greenhouse gases now in the atmosphere have been added since that time. Further, the likely consequences of warming are a matter of dispute among scientists.

- Contrary to much popular commentary and assertions by other governments, the U.S. record on emissions is quite good. In fact, most of the increase in emissions in the United States since 1990, the baseline in many emission reduction proposals, reflects population growth and the strong economic expansion following the recession that occurred in 1990, rather than declining energy efficiency. Indeed, U. S. final consumption of energy per unit of output has actually declined sharply since 1990, even more rapidly than in most other countries.

- The most rapidly growing rates of emissions are occurring in developing countries. Indeed, their emissions are so large and growing so rapidly that any projected reduction by industrialized countries would be overwhelmed by developing countries 'emissions if they are not parties to any agreement.

The economic costs associated with current emission reduction proposals are likely to be large, and to extend over a long period. Advocates of emissions control measures are using flawed models and assumptions which dramatically understate these effects. Most significantly, carbon taxes and other measures designed to reduce emissions will put U. S. companies across a wide range of industries at a severe competitive disadvantage in global markets, especially relative to those countries that may be exempt from emissions control, or that don't live up to commitments that they might make in Kyoto. This will put huge upward pressure on the already large and rising U.S. trade deficit, and will be at cross purposes with current trade policy initiatives which are designed to open foreign markets and reduce the U.S. trade imbalances. U.S. consumers would also be hurt -- higher energy costs, rising overall inflation, and higher interest rates would squeeze real income and purchasing power, and significantly reduce living standards for several decades at least.

The United States government, therefore, should be extremely cautious in dealing with the Kyoto agenda. In particular, it should not agree to proposals being made by other countries for mandatory reduction of emissions to 1990 levels by the year 2010. This would require increases in energy efficiency between now and 2010 that are virtually impossible. The only way to achieve that target would be to reduce the growth in energy consumption that results from higher levels of economic activity, thus dramatically slowing economic growth.

Nor should the United States enter into any agreement that excludes developing countries. Because the easiest and least costly emissions reductions can be achieved in developing countries, the U.S. should encourage cooperative arrangements, technology transfer and low cost finances for installation of up to date equipment in these areas. For example, a leaking gas line in the Ukraine was recently made 100 percent cleaner through the addition of joint strapping to stop the leaks. These kinds of simple inexpensive measures in countries that have not already attacked the easy problems would be a much better cost/benefit profile than draconian measures in the United States where efficiency has already been much improved.

Finally, if the Kyoto convention is really serious, it might consider cooperative financing by all attendees of a Manhattan type of project to achieve the kind of massive increases on energy efficiency that will be necessary to reduce emissions without reducing the world to poverty.

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Economic Effects of

Global Climate Change Policies

Results of the Research Efforts of the

Interagency Analytical Team

June 1997

Executive Summary

Using a group of economic models with different strengths and weaknesses, the Administration's Interagency Analytic Team has analyzed the economic effects of policies to limit emissions that lead to changes in global climate.

The starting point for this analysis was a scenario in which carbon emissions in the year 2010 were reduced to their 1990 levels. This starting point was selected because it was presented in previous Administration analyses of the issue and because it has been the subject of numerous analyses by academic researchers. Cross-border trading of emissions rights (or permits) was then allowed to reduce transitional economic losses created by such a policy. This is particularly true in the short term. A dramatic acceleration of technological progress also has made the potential to reduce further economic losses, if it can be achieved, but over a longer time period. The economic losses are also reduced by policies that use any resulting revenues for the Federal budget deficit reduction or other policies, which favor investment and long-term growth.

The starting point scenario would raise the implicit price of carbon in the economy by about $100 per ton of carbon. (Actual household burdens would be somewhat offset by conservation and presumed subsequent efficiency improvements.) These higher energy costs would produce GDP losses, at peak, between 0.2 percent and 1.0 percent of GDP. The economy would thereafter bounce back, or in the worst case stabilize, so that it would soon reach its pre-policy growth path. Thus, the losses of economic output resulting from such a policy are real, but relatively small and transient. These losses are disproportionately greater for stricter targets and disproportionately smaller for more lenient ones. However, if international permit trading were established it would moderate the losses to GDP. The maximum effect on GDP under international permit trading is about half of that under no trading.

While the economy-wide losses are small, some sectors bear large burdens, particularly energy producers. Energy-intensive industries also face greater losses. But there is no evidence of a wholesale "capital flight" from the United States resulting from an emissions reduction policy. Moreover, some industries expand as the economy undergoes the adjustment to a world with fewer carbon emissions.

Introduction

In June 1996, the Department of Energy (DOE) and the Environmental Protection Agency (EPA) sponsored a joint workshop where more than 50 experts from inside and outside the government made presentations on technical issues associated with our emissions trends and capability to reduce emissions trends in the next century. As a part of that workshop, the Interagency Analytical Team (IAT) released what were then preliminary results on the economic effects of emissions reduction proposals.

Since that June 1996 workshop, the IAT has reviewed its work, selected new modeling instruments, improved its approach to old ones, and developed a new set of modeling runs that lead to a better understanding of the economic dimensions of the climate change policy problem. This paper describes those efforts. It first summarizes the IAT model selection process. Second, it discusses the (pre-policy) base case used to measure the effects of various policy options. Third, it discusses the IAT's core emissions reduction scenario. Finally, the bulk of this paper discusses the results of the IAT's analysis.

The modeling work performed for this analysis was done by economists at DOE and EPA. The IAT also included members from the Departments of Commerce, Treasury, Labor, and State, as well as members of the White House staff. The majority of the IAT members are still primarily from DOE and EPA --the agencies that have the primary responsibility for the Administration's energy and environmental policies.

Model Selection

The first task that the IAT confronted was to review the analytic "toolbox" to assure that it had all the tools necessary to specify the economic effects of a broad range of climate change proposals. At the time, the IAT relied primarily on the Data Resources, Inc. (DRI) macro model to measure economic effects. After this reevaluation of our modeling needs, it was apparent that the complexity of the analysis would require a broader range of analytical tools.

At a public meeting last November, the IAT announced the selection of three models for its analysis. It decided to continue to use the DRI model, but also included two additional models: the Second Generation Model (SGM) and the Markal-Macro model. Each of these three models met the criteria of being available in the public sphere; being well documented; having a track record of analysis in the climate change area; being widely understood within the energy-environment community; and bringing a unique capability to the IAT's work. Used separately, but in concert with each other, they provide the broad analytical capability needed to examine the many complex economic effects of potential global climate change policies.

The DRI model is a large disequilibrium model of the domestic economy that is particularly well suited to identify transition issues based on short-run behavior embedded into a long-run model. The DRI macroeconomic model is linked to energy, regional, and industry sub-models so that macroeconomic effects of policies are translated into the effects on specific industries and regions of the country. The link to energy sub-models provides specific detailed information about the interaction of the energy sector with the rest of the economy.[1] The DRI model also includes the interaction of the financial markets with markets for goods and services and enables the analysis of the interaction of fiscal and monetary policy with the rest of the economy.

The SGM model is a computable general equilibrium good at identifying an economy's long-term trends in response to climate policies. As such, it is particularly good at describing the economy's long-term path while not as good at describing short-term transition issues. In this sense, its strengths and weaknesses are counterpoised to those of DRI. International in scope, SGM also provides detail for 12 global regions that allows the IAT to examine the effects of permit trading and joint implementation. SGM assesses the impacts of greenhouse gas emissions policies on economic growth, consumption, and energy.

The DRI model and SGM can be thought of as lying at opposite ends of an axis that measures time horizons. A second dimension of the climate change problem concerns the role of technology. Both DRI and SGM allow technological progress to move forward in response to the parameters of their models. But given the unpredictable character of innovation, the IAT concluded that a second approach would be helpful. The Markal-Macro model consists of an integrated energy supply and demand modeling system (Markal) and a macroeconomic model (Macro) useful for translating technological assumptions into economic outcomes.

The Markal-Macro model is particularly useful in answering the question, "How do we get there from here?" Markal-Macro identifies optimal, under perfect foresight, for achieving and quantified goal. Markal-Macro allows the user to control technology innovation and diffusion and its cost to the user in order to determine the levels of energy efficiencies that might be expected from a long-term policy announcement. This model also allows us to understand the implications of technology and its interaction with the economy, and helps us determine whether expected energy efficient technologies hold the key to continued economic growth.

The DRI model and the SGM model in some sense provide notional brackets for estimates of the economic effects of carbon-limiting policies. The DRI model is focused on short-term transitions and measures the economy in quarters. In some sectors, the DRI model has forward-looking behavior, but it is structured to examine the effects of short-term changes in the economy, and is often held to overstate the transitions created by broad, secular changes in the economy (and, as will be discussed below, might overstates subsequent economic improvements as well). The SGM model focuses on long-term transitions and measures the economy in five-year intervals. Thus, it risks racing past short-term transition issues, while identifying the economy's ultimate destination.

[1] The majority of the DRI results reported by the IAT use DRI's own Energy sub-model. In a limited number of cases. DOE's National Energy Modeling System (NEMS) has been also used been used in conjunction with the DRI model to analyze various sensitivities.

The Base Case

The domestic energy and emissions baseline forecasts were taken from the Energy Information Administration's 1997 Annual Energy Outlook (AEO97). The DRI baseline is DRI's own October 1996 long-term forecast, adjusted in part for the Climate Change Action Plan (CCAP). It is very similar to the AEO97 forecast, but not specifically calibrated to it. The international baseline forecast was taken from the International Energy Agency's World Energy Outlook, except for the baseline forecast of the Former Soviet Union (FSU), which came from World Bank projections. The IAT then imposed, as best possible, consistency across the models with regard to projections of baseline GDP, total energy consumption, and carbon emissions. Once these were calibrated into the 3 models, the models solved for energy prices by fuel type. Thus, the baselines of the three models are consistent, but not identical.

Tables 1 and 2 summarize the IAT baseline. In the baseline, U.S. economic growth is projected to slow over the next several decades, as the retirement of "baby boom" workers slows labor force growth and reduces the economy's potential growth rate. Energy demand therefore grows somewhat more slowly than it now does. Energy intensity, measured as energy use per dollar of GDP (the E/GDP ratio), is a key ingredient in the AEO97 forecast, because it measures the growing efficiency with which the economy uses energy. In the 1970s and 1980s, the E/GDP rate of decline averaged almost 2 percent annually—1.5 percent due to price effects and 0.5 percent due to non-price effects. Moderate price increases and the growth of more energy-intensive industries in the late 1980s led to a stabilization of energy intensity. The baseline projection used for this study incorporates a 1.0 percent annual reduction in energy consumption per unit of real output, which is taken from the EIA's Annual Energy Outlook. With these improvements included, energy demand grows at an annual rate of about 0.8 percent over the period from 1995 to 2020, tailing off at the end of the period as does economic growth.

Carbon emissions in the baseline are projected to increase by about 1.2 percent a year through 2010, and by 0.6 percent annually from 2010 to 2020, reaching 1805 million metric tons in 2020. In 1990, the year most frequently used in the international negotiating process as the reference level of carbon, carbon emissions were 1,340 million metric tons, 22 percent below EIA's projection for 2010 and 36 percent below DRI's projection for 2020.

Table 1: IAT Domestic Baseline

	Year							Average Annual Growth Rate (percent) [1]					
	1990	1995	2000	2005	2010	2015	2020	90-95	95-00	00-05	05-10	10-15	15-20
Population													
DRI-DRI Energy	250	263	276	287	299	311	323	1.0	0.9	0.8	0.8	0.8	0.7
AEO97 (NEMS) [2]	250	264	276	287	299	311	n/a	1.0	0.9	0.8	0.8	0.8	n/a
SGM	250	263	276	287	299	311	323	1.0	0.9	0.8	0.8	0.8	0.7
Markal-Macro	250	263	276	287	299	311	323	1.0	1.0	0.8	0.8	0.8	0.8
GDP (Billion 1992$)													
DRI-DRI Energy	$6,139	$6,743	$7,515	$8,320	$9,163	$9,996	$10,670	1.9	2.2	2.1	1.9	1.8	1.3
AEO97 (NEMS)	$6,139	$6,739	$7,544	$8,390	$9,185	$9,880	n/a	1.9	2.3	2.1	1.8	1.5	n/a
SGM	$6,139	$6,739	$7,544	$8,390	$9,185	$9,880	$10,591	1.9	2.3	2.1	1.8	1.5	1.4
Markal-Macro	$6,139	$6,739	$7,549	$8,384	$9,198	$9,880	$10,498	1.9	2.3	2.1	1.9	1.4	1.2
OMB [3]	$6,142	$6,721	$7,470	$8,343	$9,225	$9,929	$10,581	1.8	2.1	2.2	2.0	1.5	1.3
Total Energy Consumption (Quads) [4]													
DRI-DRI Energy	82.6	88.9	95.9	101.0	105.3	107.4	108.9	1.5	1.5	1.0	0.8	0.4	0.3
AEO97 (NEMS)	83.7	90.0	97.9	103.4	107.9	110.9	n/a	1.5	1.7	1.1	0.9	0.5	n/a
SGM	81.2	90.6	96.0	102.0	107.0	110.3	113.0	2.2	1.2	1.2	1.0	0.6	0.5
Markal-Macro	83.7	90.9	98.0	103.7	107.8	110.7	115.3	1.7	1.5	1.1	0.8	0.5	0.8
Energy Intensity (TBtu/$92GDP)													
DRI-DRI Energy	13.5	13.2	12.8	12.1	11.5	10.7	10.2	-0.4	-0.7	-1.0	-1.1	-1.3	-1.0
AEO97 (NEMS)	13.6	13.4	13.0	12.3	11.7	11.2	n/a	-0.4	-0.6	-1.0	-1.0	-0.9	n/a
SGM	13.2	13.5	12.8	12.2	11.6	11.2	10.7	0.4	-1.0	-1.0	-1.0	-0.9	-0.9
Markal-Macro	13.6	13.5	13.0	12.4	11.7	11.2	11.0	-0.2	-0.8	-1.0	-1.1	-0.9	-0.4
Minemouth Coal Price ($95/ton)													
DRI-DRI Energy	$23.92	$18.45	$15.28	$14.41	$13.76	$13.16	$12.70	-5.1	-3.7	-1.2	-0.9	-0.9	-0.7
AEO97 (NEMS)	$19.88	$18.83	$18.38	$17.47	$16.92	$15.46	n/a	-1.1	-0.5	-1.0	-0.6	-1.8	n/a
SGM	$19.88	$19.45	$18.48	$17.30	$16.47	$15.73	$14.96	-0.4	-1.0	-1.3	-1.0	-0.9	-1.0
Markal-Macro	$19.88	$18.83	$17.37	$16.39	$15.90	$16.39	$16.14	-1.1	-1.6	-1.2	-0.6	0.6	-0.3
World Oil Price ($95/Barrel)													
DRI-DRI Energy	$25.23	$17.14	$16.18	$18.93	$21.24	$22.86	$23.95	-7.4	-1.1	3.2	2.3	1.5	0.9
AEO97 (NEMS)	$24.87	$17.26	$18.20	$19.72	$20.41	$20.98	n/a	-7.0	1.1	1.6	0.7	0.6	n/a
SGM	$24.87	$17.26	$18.20	$19.72	$20.41	$20.98	$21.57	-7.0	1.1	1.6	0.7	0.6	0.6
Markal-Macro	$24.87	$17.26	$18.59	$19.75	$20.29	$21.05	$22.20	-7.0	1.5	1.2	0.5	0.7	1.1
Natural Gas Price (wellhead $95/Mcf)													
DRI-DRI Energy	$1.81	$1.46	$1.87	$2.15	$2.42	$2.54	$2.65	-4.2	5.1	2.8	2.4	1.0	0.9
AEO97 (NEMS)	$1.97	$1.61	$1.82	$1.94	$2.01	$2.13	n/a	-4.0	2.5	1.3	0.7	1.2	n/a
SGM	$1.97	$1.99	$2.07	$2.10	$2.16	$2.11	$1.97	0.2	0.9	0.2	0.6	-0.5	-1.4
Markal-Macro	$1.71	$1.55	$2.22	$2.28	$2.46	$2.77	$2.97	-1.9	7.4	0.5	1.6	2.4	1.4
Gasoline Prices ($95/Gal) [5]													
DRI-DRI Energy	$1.40	$1.21	$1.20	$1.26	$1.31	$1.37	$1.40	-2.9	-0.1	1.0	0.8	0.8	0.4
AEO97 (NEMS)	$1.34	$1.15	$1.19	$1.21	$1.22	$1.17	n/a	-3.1	0.8	0.3	0.1	-0.7	n/a
SGM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Markal-Macro	$1.34	$1.15	$1.34	$1.39	$1.40	$1.41	$1.44	-3.0	3.1	0.7	0.1	0.1	0.4
Carbon Emissions (MMTC) – Total													
DRI-DRI Energy	1338	1413	1516	1612	1693	1767	1805	1.1	1.4	1.2	1.0	0.9	0.4
AEO97 (NEMS)	1339	1424	1543	1639	1722	1799	n/a	1.2	1.6	1.2	1.0	0.9	n/a
SGM	1350	1480	1550	1637	1729	1808	1871	1.9	0.9	1.1	1.1	0.9	0.7
Markal-Macro	1338	1459	1574	1674	1741	1806	1914	1.7	1.5	1.2	0.8	0.7	1.2

1 Growth rates are calculated from non-rounded levels. 2 AEO97 projections extend only to 2015. 3 Office of Management and Budget fiscal year 1998 assumptions. 4 SGM projections do not include geothermal, wind, biomass waste, and other municipal waste. 5 The SGM model does not include gasoline.

Table 2: IAT International Baseline Average Annual Growth Rates (percent)

	Real Economic Growth (GDP)			Energy Growth (Quads)			Emissions Growth (MMTC)		
	1990-00	2000-10	2010-20	1990-00	2000-10	2010-20	1990-00	2000-10	2010-20
Australia	2.8	2.8	2.6	2.1	1.5	0.9	2.0	1.5	0.9
Canada	2.6	2.5	1.2	1.7	1.0	0.4	2.2	1.4	0.7
China	8.4	7.5	5.8	3.9	2.8	2.1	3.8	2.8	2.2
Former Soviet Union	-3.5	4.6	4.2	-3.5	1.8	1.2	-4.0	1.8	1.2
Eastern Europe	-4.5	4.2	4.3	-3.0	1.3	1.2	-3.5	1.3	1.2
India	4.1	4.5	3.9	3.9	3.3	3.1	4.1	2.1	3.3
Japan	2.1	1.7	0.9	2.2	0.9	0.1	2.1	0.9	0.1
Korea	5.0	5.9	4.4	4.0	3.1	2.4	2.6	3.3	2.9
Mexico	4.0	4.0	3.2	4.2	2.9	2.3	4.2	2.9	2.4
Western Europe	2.3	2.5	2.4	1.5	1.4	0.6	1.2	1.4	0.6
United States	2.1	2.2	1.4	1.7	1.1	0.6	1.4	1.1	0.8
Rest-Of-World	3.6	3.4	3.0	3.0	2.0	2.0	3.0	2.2	2.2

The Analytical "Starting Point"

The IAT began its analysis of emissions reductions policies by examining one core emissions reduction scenario. Then we explored the economic effect of changes to this scenario. The central policy modeled -- the "starting point" scenario -- is aimed at reducing carbon and other greenhouse gas emissions by stabilizing them at 1990 levels. The "starting point" scenario pursues those reductions by issuing tradable emission permits at the earliest point of energy production or when imported into the United States. The policy is announced in 2000 and its restrictions are phased-in over a ten year period, so that the policy takes full effect in 2010. The permits are initially auctioned so that all revenues generated through permits would be recycled through the economy through deficit reduction. The initial discussion of the "starting point" scenario assumes no international cooperation. An option incorporating international trading is discussed once the dynamics of the no trading "starting point" scenario have been established.

Estimates of reductions of non-carbon emissions, such as methane and forest carbon sinks, are obtained from engineering estimates outside the models. Early in the process, the IAT estimated a strike-price for these sources of $70 per ton (which turned out to be low). Appendix Table A shows baselines for, and the quantities of emissions obtained from, these non-carbon sources at this price. These carbon tons were subtracted from the emissions targets being modeled. But the cost of obtaining them was not factored back into the models and, is therefore missing. While the engineering estimates are uncertain, the cost of abating non-carbon sources could increase the estimates of economic effects by as much as 14 percent.

The "starting point"scenario was employed as an analytical starting point for this analysis primarily because it has already been the subject of much attention within the analytical literature. Most analysts of climate change policies have used an emissions freeze in the year

2010 at 1990 levels as their framework. The IAT, therefore, used this scenario in order to facilitate comparisons of its work to that of other researchers.

Industry and regional effects, as presented here, show only the effects of the climate change policy on the industry's output (shipments plus inventory change). We considered this our first step in understanding the likely sectoral consequences of emissions reductions.

The "starting point" scenario incorporates a slight improvement in energy intensity (E/GDP) over the EIA/AEO baseline, which declines by 1.0 percent per year. This improvement could come about because the climate change policy undertaken generates foreseeable increases in the future price of energy, or because of the implementation of the Climate Change Action Plan (CCAP), or other policies. The prospective "announcement effect," therefore, is what allows the model to distinguish between a change in future policy regarding carbon emissions and an exogenous shock, such as the two oil price increases in the 1970s. This leads to somewhat faster rate of diffusion of energy efficient technologies and a higher rate of innovation through R&D in anticipation of future higher energy prices. The IAT assumes an improvement in energy-intensity of 0.25 percent so that the total annual change in the ratio of energy to GDP is 1.25 percent per year. A faster technology alternative is also investigated. (More detail on energy-efficient technology improvement is provided later in this paper.)

Unless otherwise stated, the tables and figures that follow were derived using the DRI model and using the "starting point" scenario, which does not incorporate international emissions trading. These estimates, therefore, will be at the high end of the likely range, due to both model structure and the absence of trading.

"Starting Point" Results

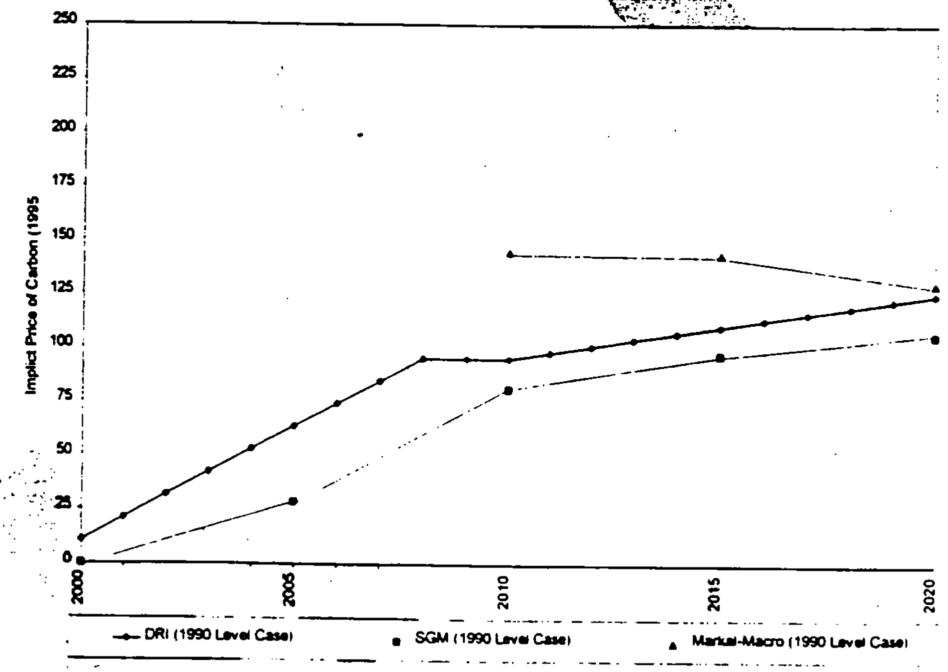
<u>Estimates of permit prices are around $100 per ton of carbon in 2010 and rising slightly thereafter, and are consistent across models</u>. While the three models used for this analysis vary in structure and often in terms of macroeconomic outcomes, they generate fairly consistent results as to the implicit price of carbon in the economy. Table 3 presents the results obtained by the three models for the value of a permit to emit a ton of carbon. Figure 1 shows the path for the value of carbon in these models. All of these estimates pertain to the "starting point" option in which emissions are frozen at their 1990 level in 2010 and thereafter.

Table 3: The Implicit Price of Carbon (1995$) in 2010 and 2020
1990 Level Case, No International Trading

	2010	2020
DRI-DRI Energy	95	125
SGM	81	106
Markal-Macro	145	130
NEMS	n/a	n/a

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP. SGM permit prices are calculated using the rate of change in carbon to GDP (C/GDP), which incorporate emission rates by the different fuel types. NEMS estimates are forthcoming.

Figure 1: Price Path of the Implicit Price of Carbon (1995$)
1990 Level Case, No International Trading



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP. SGM permit prices are calculated using the rate of change in C/GDP. SGM and Markal-Macro models use data and generate results in five year intervals.

The DRI model concludes that an implicit price of $95 (1995$) per ton of carbon in 2010 would result in stabilization. The Markal-Macro model estimated $145 (1995$) while the SGM model predicted about $81 (1995$), in 2010.[2] A permit price of $100 per ton is the equivalent of a price increase of 26 cents per gallon of refined petroleum product, $1.49 per thousand cubic feet of natural gas, $52.52 per ton of coal, and 2 cents per kilowatt hour of electricity produced.

matching $100 increase right?

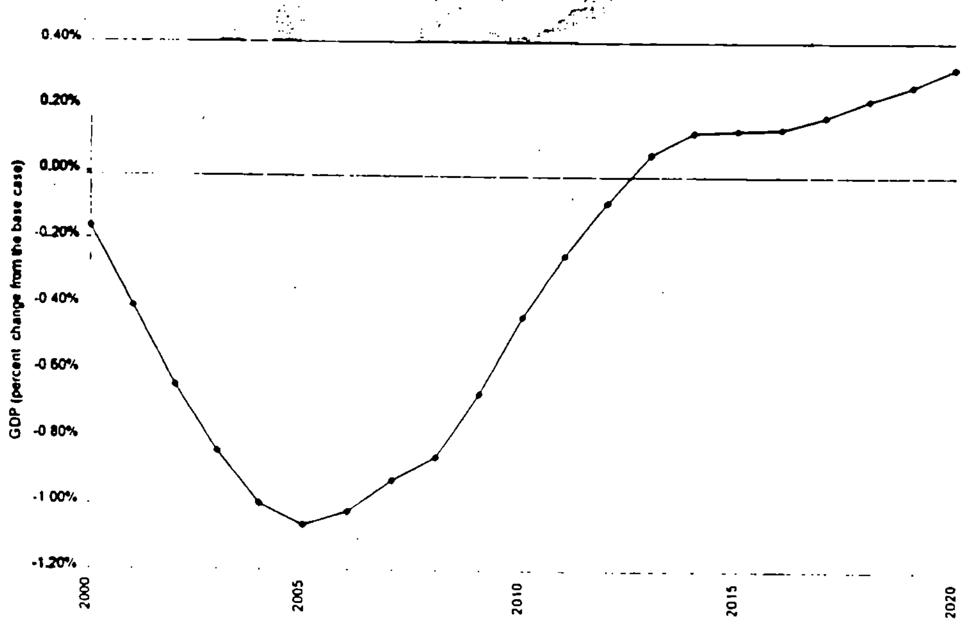
[2] The higher permit price from the Markal-Macro model reflects, in part, differences in model structure, but results mostly from differences in the calibrations of baseline emissions.

The models also agree that this implicit price of carbon grows somewhat over time. This reflects the fact that the 1990 emission ceiling becomes a progressively more binding constraint over time, given projected growth in base case emissions. By the year 2020, the implicit price of carbon rises to $125, $106 and $130 per ton (1995$) in the DRI, SGM, and Markal-Macro models, respectively.

Emissions reductions lead to small reductions in short-term economic growth (GDP), but growth later appears to recover. The burden of reducing carbon and other greenhouse gas emissions leads to short-term reductions in economic growth as measured by GDP. These reductions, however, are not large and, in many instances, are recovered in later years.

Results from the DRI model are presented in Figure 2. The results indicate that there is an initial GDP loss as the emission-limiting policy begins to be phased in. These losses cumulate to a peak loss of about one percent of total economic output in the year 2005 -- that is, the economy's growth slows until the size of the economy is, at worst, about one percent smaller in that year when compared to the base case. After 2005, the economy actually grows faster than it would have absent climate change policy and starts to make up the lost ground. By the year 2013, the economy is back to the point at which it would have been had no policy been enacted. In subsequent years, the economy improves slightly compared to the "no policy" base case--this differential reaches 0.3 percent by 2020, the last year of the model run.

Figure 2: DRI-DRI Energy 1990 Level Case, No International Trading--Gross Domestic Product

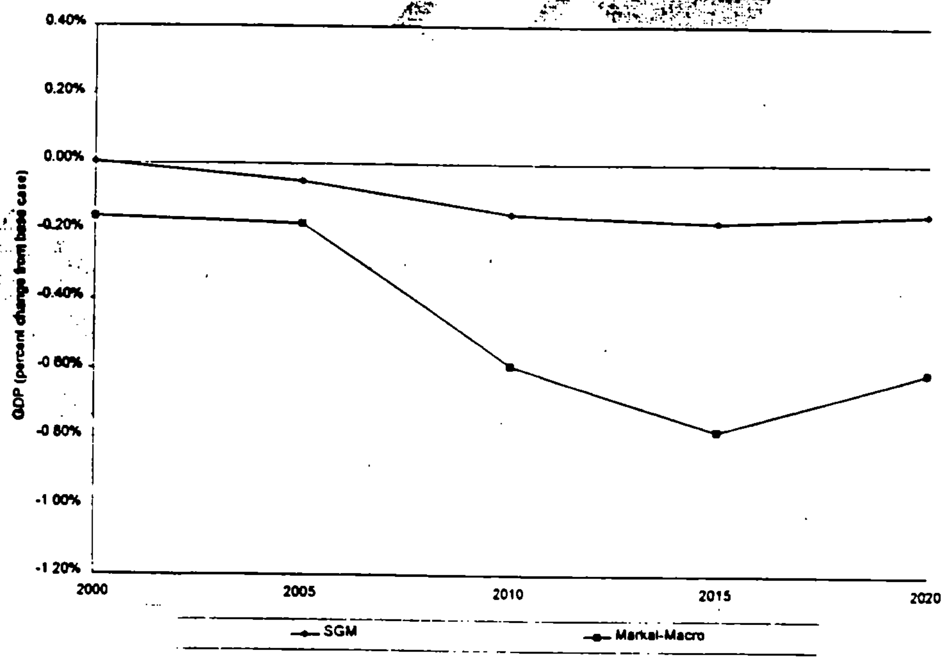


Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP

This improvement occurs in the DRI model because the emissions reduction policies modeled have some effects that favor savings and investment at the expense of consumption. If the Federal government auctions off emissions permits, it acquires the wherewithal to reduce the deficit (or retire debt) and, in effect, increase the nation's savings. This allows the cost of capital to fall and favors investment. The marginal profitability of investment also rises under these policies because new investment allows firms to neutralize higher energy costs. In effect, capital is a long-term substitute for energy and is favored after a transition period. Thus, the cost of investment falls and the incentive to invest is strengthened. This faster rate of investment (discussed in greater detail below) gives the economy a newer and larger capital stock: as a result the economy's ability to grow improves until it actually reaches a modestly higher growth path in the years following the transition.

Figure 3 shows comparable results for the SGM and Markal Macro models. In contrast to the DRI model, which focuses on short-term transition issues and may, therefore, tend to produce larger estimates of GDP losses, the SGM and Markal-Macro models move quickly through these issues and focus on longer-term prospects. The SGM model estimates peak losses for the economy of 0.17 percent of GDP in 2015, but the economy then stabilizes through 2020.

Figure 3: SGM and Markal-Macro 1990 Level Case
No International Trading, Gross Domestic Product



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in C/GDP.

The Markal-Macro simulation results show a reduction in GDP of 0.60 percent from baseline in 2010 in the stabilization case. GDP remains below baseline levels throughout the forecast horizon. The GDP impact profile reflects the model structure, which represents the base case solution as a set of optimal energy use and technology choices given fuel prices, technology characteristics, and discount rates. Since a carbon constraint limits the use of fuels and technologies that would otherwise be chosen, projected GDP must fall. Moreover, since the balance between investment and consumption is optimized within each case considered, economic welfare cannot be increased by an investment-oriented revenue recycling scheme. Consequently, although investment will adjust, the maximization of economic welfare under a carbon constraint does not lead to higher GDP in the future years in the Markal-Macro model.

The models used by the IAT offer a similar picture in some regards--all show initial losses in aggregate economic output that are not very large (even the DRI peak loss is spread over five years). But they also differ in predictable ways, given their structure. A recent analysis by Dr. Robert Repetto and Dr. Dunkin Austin of the World Resources Institute examined 162 analyses of climate change policy and found that model structure can account for two-thirds of the difference in results, if environmental benefits are ignored.[3]

Disequilibrium macro models, such as DRI, tend to identify deeper transitional losses and steeper transitional rebounds. Computable general equilibrium models, such as SGM, see more sanguine short-term effects and see the economy stabilizing after a more frictionless adjustment. The SGM model, however, is less flexible than some computable general equilibrium model because it does not allow instantaneous shifts in capital. The SGM model maintains vintaged capital stock in the electricity sector and retires old electricity related capital only when it cannot cover operating expenses or reaches its fixed lifetime. This feature allows the analysis to incorporate the costs of reallocating capital stock.

Which, then, is right? DRI's transitional losses may be overstated, but so would be the rebound and the shift to a higher growth path it estimates for later years. SGM and Markal-Macro probably understate the transitional problem, but also avoid the later-year growth surge that DRI sees as driven by higher levels of investment. The models probably serve as brackets for the range of reasonable estimates of the economic effects of an emissions freeze at 1990 levels in 2010 and thereafter.

Unemployment and Inflation. The effect of the emissions stabilization policy results in approximately a 0.2 percentage point increase in the unemployment rate from 2001 through 2011, with a peak increase of about 0.4 percentage points in 2015, as estimated using the DRI model. The unemployment rate first rises as GDP falls, but then returns to its pre-policy level by 2012, as shown in Figure 4. The inflation rate increases by about 0.3 percentage points until 2009, measured by the annual rate of change in the Consumer Price Index (CPI). The annual rate of change in the CPI declines by about 0.1 to 0.2 percentage points per year for 2010 through 2020, as shown in Figure 5.

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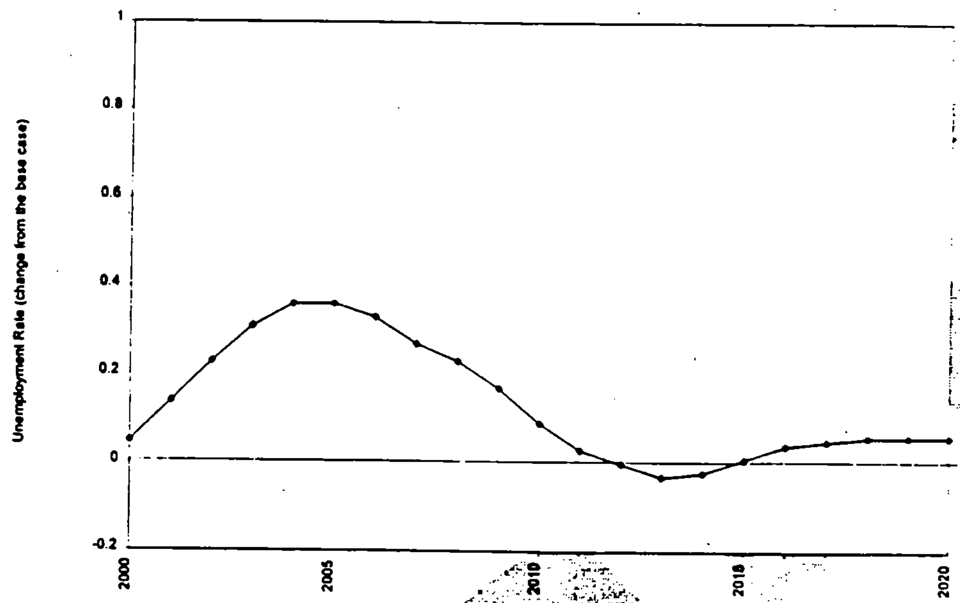
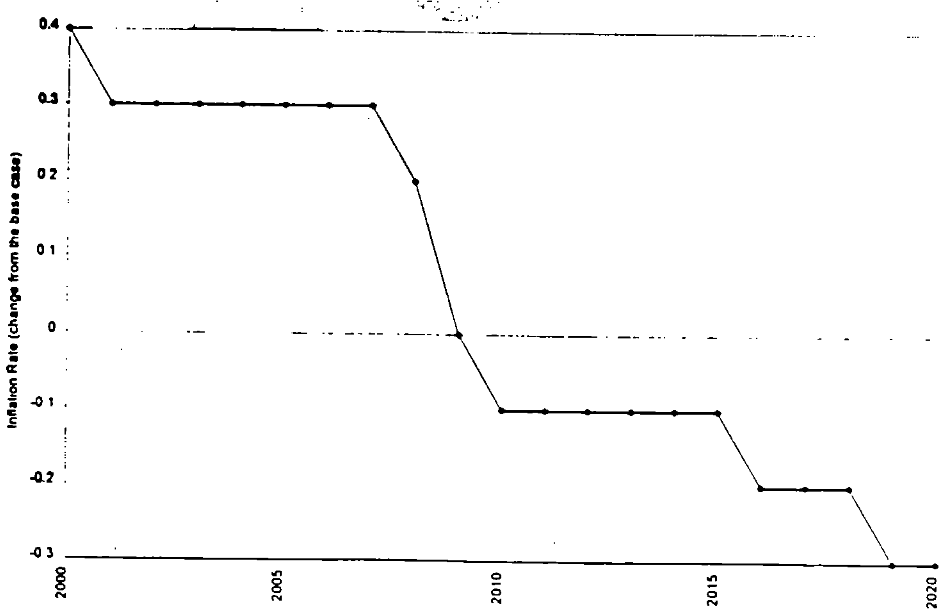
[3] Repetto. Robert and Dunkin Austin. "The Cost of Controlling CO2 Emissions: A Guide for the Perplexed." *World Resources Institute* (Forthcoming).

Figure 4: DRI-DRI Energy 1990 Level Case, No International Trading--Unemployment Rate



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 5: DRI-DRI Energy 1990 Level Case, No International Trading--Inflation Rate

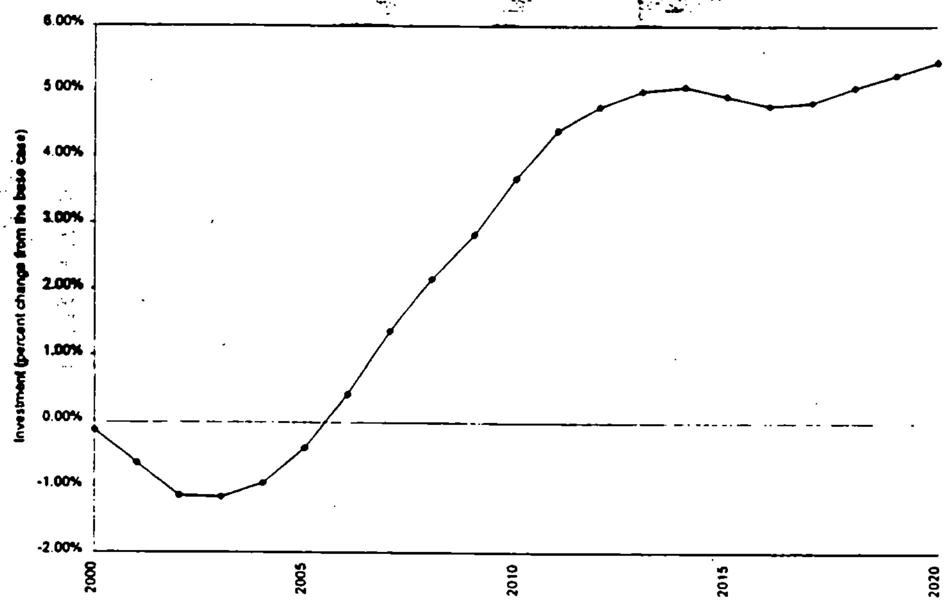


Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Investment policies are key to getting the economy back on track. In the baseline forecast, slow labor force growth of 0.8% per year leads to slow potential GDP growth, which results in slow capital stock turnover. The slower rate at which the capital stock is renewed is of direct consequence to mitigating carbon and other related emissions, since improvements in energy-efficiency or carbon-abating technologies generally must be embodied in the capital stock in order to be effective. Thus, any global climate change policy, to be effective, must focus on investment at the expense of consumption. The deficit reduction policy option, one of the several revenue recycling options examined, promotes savings, which boosts this investment.

The DRI model suggests that investment under a climate change policy scenario begins to exceed investment in the baseline by 2006, as seen in Figure 6. By the time the policy is fully implemented in 2010, investment exceeds the baseline by about $50 billion (1992$), with this difference rising to about $100 billion in 2020. Personal Consumption Expenditures (PCE), on the other hand, remain below the baseline level throughout the forecast period, so that PCE drops by about $80 billion in 2008, as seen in Figure 7. After the trough in 2008, PCE gradually moves toward baseline by 2020.

Figure 6: DRI-DRI Energy 1990 Level Case, No International Trading--Investment

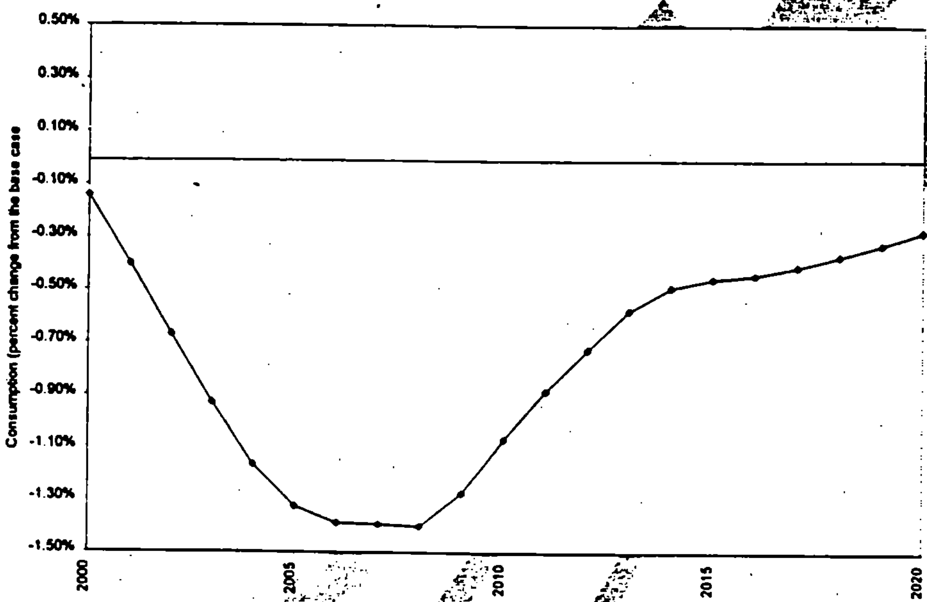


Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

The faster rate of investment drives the rebounding of real economic growth in the later years of the model simulation. But it should be noted that consumption does not rebound in the same manner, although it does recover from its peak losses, as seen in Figure 7. But consumption can be taken as the measure of economic activity that is closer to consumer "welfare" than total GDP.

which includes investment, because consumption includes all activities that are of direct consequence to households. Thus, while increases in investment drive the economy's growth path back to and perhaps even above its original trend, it does so by diverting resources away from uses that allow consumers to enjoy them directly in the short term.

Figure 7: DRI-DRI Energy 1990 Level Case, No International Trading--Consumption



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

The paths of consumption and investment following the imposition of a climate change policy depend critically on assumptions regarding the manner in which revenue flows related to the allocation of emissions permits are managed and the conduct of monetary policy by the Federal Reserve. These sensitivities are discussed in a later section.

Among fuels, demand for coal bears the brunt of greenhouse gas stabilization The reduction in energy-related greenhouse emissions in the 2010 time frame will require a combination of three types of energy system changes: increased end-use efficiency, reduced end-use activity, or fuel-switching towards an increased market share of low- and no-carbon fuels in the energy mix. Increased end-use efficiency or reduced end-use activity tends to lower the demand for all fuels, while fuel-switching favors low- and no-carbon fuels, such as natural gas and renewable energy, relative to coal. The three models used by the IAT place different emphasis on these three strategies, with corresponding differences in projected fossil fuel impacts.

Table 4 presents the effects of carbon-limiting policies on the economy's energy consumption and fuel mix. Using the DRI model, total energy consumption falls from 105 quadrillion Btus (quads) in the base case in 2010 to a level of 88 quads under the policy, a reduction of 16 percent in that year. By 2020, energy consumption in the economy has declined by 20 percent, from 109 quads to 87 quads, when compared to the base case for that year. The table shows comparable results using the Markal-Macro model, when the 1990-level emissions freeze produces a decline in projected energy consumption of 14 percent in 2010 and 16 percent in 2020. SGM model results are similar to both the DRI and Markal-Macro results; energy consumption drops by 15 percent in 2010, and 20 percent in 2020.

Table 4: Effects of Carbon Stabilization on Energy Consumption and Fuel Mix (quadrillion Btus)

	1990	2010		2020	
	Actual	Base case	1990 Level Case, No International Trading	Base case	1990 Level Case, No International Trading
DRI-DRI Energy					
Total U.S. Energy Consumption	84.3	105.3	88.2	108.9	86.7
Natural Gas	19.3	27.4	22.9	29.8	24.9
Oil	33.6	41.1	35.6	44.1	37.4
Coal	19.0	24.3	17.2	25.8	15.2
SGM					
Total U.S. Energy Consumption	84.3	107.0	91.4	113.0	90.0
Natural Gas	19.3	33.2	33.1	37.7	36.7
Oil	33.6	36.5	33.1	39.0	34.0
Coal	19.0	23.9	11.3	25.8	8.5
Markal-Macro[1]					
Total U.S. Energy Consumption	84.3	107.8	92.6	115.6	96.7
Natural Gas	19.3	29.0	30.7	35.1	36.7
Oil	33.6	43.4	37.9	45.0	40.1
Coal	19.0	22.5	9.4	24.6	4.7
NEMS					
Total U.S. Energy Consumption	n/a	n/a	n/a	n/a	n/a
Natural Gas	n/a	n/a	n/a	n/a	n/a
Oil	n/a	n/a	n/a	n/a	n/a
Coal	n/a	n/a	n/a	n/a	n/a

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP. SGM uses a similar rate of change in C/GDP. 1. Under the Markal-Macro results, the increase in the use of renewable energy sources, such as wind, account for the difference the total U.S. energy consumption and the sum of the component fuels. NEMS estimates are forthcoming.

DRI, Markal-Macro, and SGM demonstrate that dampened energy consumption and reduced carbon emissions are concentrated in coal use. As seen in Table 5, DRI results show that about 57 percent of the total emissions reductions in 2010 result from reduced demand for coal, 30 percent from oil, and 13 percent from natural gas. By 2020, 65 percent of emission reductions are generated from reductions in demand for coal. This translates to a 25 percent total emission reduction for coal in 2010 and a 36 percent reduction in 2020. Markal-Macro produces somewhat similar results: it shows that about 57 percent of total emissions reductions in 2010 occur due to reduced coal use; and 16 percent due to reduced oil use; while natural gas consumption is 5 percent above the base case. By 2020, coal accounts for about 80 percent of emissions reductions. The SGM model results are also similar; i.e., coal is responsible for 80 percent of emissions reductions in 2010 and 2020.

The different spread of percent of total emissions reductions by fuel occurs because renewable energy sources and increases in the consumption of natural gas play important roles in the Markal-Macro and SGM models. It is also true because DRI's model sees strong transportation demands and more limited technological prospects for serving it, while transportation choices do not take into account price expectations. This is in contrast to DRI's treatment of the utility sector, which is relatively forward looking when examining fuel choices.

Table 5: 1990 Level Case, No International Trading—Percent of Total Emissions Reduction by Fuel

	2010	2020
DRI-DRI Energy		
Natural Gas	13	8
Oil	30	28
Coal	57	65
SGM		
Natural Gas	0	3
Oil	18	18
Coal	82	79
Markal-Macro		
Natural Gas	-5	-4
Oil	16	15
Coal	57	80
NEMS		
Natural Gas	n/a	n/a
Oil	n/a	n/a
Coal	n/a	n/a

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP. NEMS estimates are forthcoming.

On the demand side, according to DRI, about 46 percent of total emission reductions in 2010 come from the electric sector due to fuel switching and decreases in demand for electricity, 26 percent come from reduced demand for transportation and 19 percent come from reduced demand by the industrial sector, as shown in Table 6. The commercial and residential sectors contribute a combined 8 percent to the total of emissions reductions. The corresponding estimates obtained from the Markal-Macro model show that electricity uses account for 40 percent of total reduction in emissions, and transportation, industrial, and residential and commercial uses for 16 percent, 17 percent, and 15 percent, respectively.

Table 6: 1990 Level Case, No International Trading
Percent of Total Emissions Reduction by Demand Sector

	2010	2020
DRI-DRI Energy		
Residential	5	4
Commercial	3	2
Industrial	19	21
Transportation	27	25
Electricity	46	47
SGM		
Residential	n/a	n/a
Commercial	n/a	n/a
Industrial	n/a	n/a
Transportation	n/a	n/a
Electricity	n/a	n/a
Markal-Macro		
Residential and Commercial	15	15
Industrial	17	22
Transportation	16	17
Electricity	40	53
NEMS		
Residential	n/a	n/a
Commercial	n/a	n/a
Industrial	n/a	n/a
Transportation	n/a	n/a
Electricity	n/a	n/a

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP. SGM uses a similar rate of change in C/GDP. SGM does not generate data by demand sector. NEMS estimates are forthcoming.

Thus, across models and when viewed from different perspectives, the majority of reductions in emissions obtained under the broadest strategies comes from reducing utility consumption of coal. Reducing coal use under utility boilers is generally the largest, cheapest option to reduce carbon emissions in the economy. This is accomplished through better operating rates and through the substitution of gas-fired combined-cycle units for coal-fired units. The implicit price of carbon obtained in most model runs is usually the one that accomplishes this transition in electricity baseload. The range of carbon values -- generally about $100 per ton in the no trading cases -- is as high as it is because most coal-fired units are fairly old and already fully amortized. Thus, their product costs mainly consist of fuel and operating and maintenance expenses but not capital costs. The price of coal, therefore, must rise considerably to make coal-fired electricity more expensive on the margin than electricity generated by a new gas-fired plant that entails new capital costs.

International trading of carbon permits among the Annex I countries leads to sizable reductions in costs needed to stabilize emissions. The discussion so far has centered on the how the U.S. economy reacts when the United States independently reduces emissions. However, establishing an international market to trade emissions permits is a preferred to unilateral action that has been proposed by the United States for inclusion in a multinational agreement. The purpose of such a market would be to increase the efficiency and lower the cost of reducing global emissions by giving all emitters the incentive to search for least-cost solutions across national boundaries.

In brief, under a system of tradable permits, a country could either reduce emissions domestically or purchase additional emissions "rights" (i.e., permits) from other countries. Countries with opportunities to reduce emissions that cost less than the going permit price would have an incentive to reduce emissions and sell their "right to emit" for cash. Countries that had only high cost options to reduce emissions (that is, reduction options that cost more than the permit prices) could purchase emission permits. The forces of supply and demand would set the permit price and the market incentives would push the trading group, as a whole, to institute the least cost emissions reductions first. As a result, it costs less for the trading group, as a whole, to reach the target emissions levels, than it would for each country unilaterally to reduce its emissions to the target levels. Such a policy, of course, raises a variety of legal and institutional questions regarding how it would be implemented with certainty. These issues are not addressed here: instead, the simple assumption is made that the policy works as intended and least-cost approaches to abating carbon are identified and traded.

Using the SGM model, the IAT modeled two international trading scenarios. In the first, it examined the affects of establishing a permit market among the United States, Canada, Western Europe, Eastern Europe, Japan, the Former Soviet Union (FSU), and Australia (collectively known as Annex I countries under the Climate Convention). In the second scenario, it examined the effects of Joint Implementation, that is, establishing a wider permit market that includes the rest of the world. These scenarios are compared to a scenario in which each of the Annex I countries independently implemented our "starting point" scenario for stabilizing carbon emissions; that is, stabilizing emissions at 1990 levels in 2010 with a ten year phase in, where revenues are used to reduce the deficit, and under the assumption of moderate technological change (i.e., a 0.25 percent increase over the baseline in the annual increase in energy or carbon efficiency).

International emissions trading calls into question one of the basic assumptions regarding international compliance when performing the estimates. This concerns the case of the FSU. The "starting point" case assumes that all countries are restricted to their 1990 emissions level before they trade. The FSU nations, however, will have emissions below their 1990 levels for years to come. Thus, under this rule, they would be able to sell to other nations their "right to emit" up to their 1990 levels, but would not have to perform any actual emissions reductions. Thus, emissions trades would not result in "corresponding reductions" in annual emissions.

The IAT performed its analysis both with and without "corresponding reductions." The case without "corresponding reductions" allows the FSU to sell emissions rights up to its 1990 base. The case with "corresponding reductions" does not allow these trades. Instead the IAT specified that if a nation's emissions were below their 1990 level in the base case, its baseline for the purposes of trading was shifted down from the 1990 level to whatever the nation's actual emissions would be. For example, the FSU had carbon emissions of 1050 million metric tons (MMT) in 1990, and is projected to have emissions of 836 MMT in 2010. Their baseline in

2010, therefore, is 836 MMT, even though it is lower than the 1990 level. Thus, any tons "sold" from the FSU in these simulations represent actual emissions reductions. The results obtained using the SGM model appear in Tables 7a and 7b.

Under the Annex I trading scenario, the United States, Canada, Western Europe, Japan, and Australia each bear real costs for emissions reduction. The losses experienced by the different nations reflect the economic assumptions made for them (which are presented earlier in this report, in Table 2) and their energy policies to date. Japan, for example, is projected to have relatively slow economic growth and already has relatively high energy prices and an extensive nuclear program. Thus, it is not projected to have strong growth in emissions over the next few decades. Japan has a high implicit price of carbon ($268 per ton) as shown in Table 8. Western Europe fares somewhat worse than the United States, since its economic growth is projected to be stronger, and its energy policies have already been raised.

Table 7a: SGM 1990 Level Case--GDP Impacts to Annex I Countries
No Trading vs. Annex I Trading

	No Trading					Annex I Trading (With Corresponding Reductions)				
	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
Australia	0.0%	-0.2%	-0.5%	-0.4%	-0.2%	0.0%	-0.1%	-0.3%	-0.2%	-0.1%
Canada	0.0%	-0.4%	-1.1%	-1.1%	-1.1%	0.0%	-0.1%	-0.4%	-0.3%	-0.2%
Eastern Europe	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.3%
Former Soviet Union	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.5%	0.6%	0.5%
Japan	0.0%	-0.2%	-0.6%	-0.4%	-0.3%	0.0%	-0.1%	-0.2%	-0.1%	-0.1%
Western Europe	0.0%	-0.2%	-0.7%	-0.4%	-0.2%	0.0%	-0.1%	-0.3%	-0.2%	-0.1%
United States	0.0%	-0.1%	-0.2%	-0.2%	-0.2%	0.0%	-0.1%	-0.1%	-0.1%	-0.1%

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in C/GDP.

Table 7b: SGM 1990 Level Case--GDP Impacts to Annex I Countries
No Trading vs. Annex I Trading

	No Trading					Annex I Trading (With out Corresponding Reductions)				
	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
Australia	0.0%	-0.2%	-0.5%	-0.4%	-0.2%	0.0%	0.0%	-0.1%	-0.2%	-0.1%
Canada	0.0%	-0.4%	-1.1%	-1.1%	-1.1%	0.0%	0.0%	-0.2%	-0.2%	-0.2%
Eastern Europe	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.7%	0.5%
Former Soviet Union	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.5%	0.5%
Japan	0.0%	-0.2%	-0.6%	-0.4%	-0.3%	0.0%	0.0%	-0.1%	-0.1%	-0.1%
Western Europe	0.0%	-0.2%	-0.7%	-0.4%	-0.2%	0.0%	0.0%	-0.2%	-0.2%	-0.1%
United States	0.0%	-0.1%	-0.2%	-0.2%	-0.2%	0.0%	0.0%	-0.1%	-0.1%	-0.1%

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in C/GDP.

GDP losses in Canada are the most severe among the Annex I countries. Canada is already less carbon intensive, but not as energy efficient as other Annex I countries. For example, Canada's carbon to population ratio is about 17 percent below that of the United States, while its energy to GDP ratio is about 46 percent higher. Canada also relies more heavily on non-carbon sources of energy, such as hydroelectrical generation, making emissions reductions more difficult to come by.

Table 8 shows the implicit price of carbon by country without trading, trading with Annex I countries, and with Joint Implementation with the developing countries. The United States shows smaller output losses than Japan or Western Europe predominantly because it has more "cheap" carbon-abating opportunities. Thus, it is somewhat easier for the United States to reach emission targets than other regions, which have already "picked the low fruit."

Table 8: Implicit Price of Carbon (1995$) Under Annex I Trading and Joint Implementation--SGM 1990 Level Case

	2010					2020				
	No Trading	Annex I Trading		Joint Implementation		No Trading	Annex I Trading		Joint Implementation	
		with CR	without CR	with CR	without CR		with CR	without CR	with CR	without CR
Australia	132	56	23	20	9	126	50	35	16	12
Canada	222	56	23	20	9	252	50	35	16	12
China	*	n/a	n/a	20	9	*	n/a	n/a	16	12
Former Soviet Union	0	56	23	20	9	0	50	35	16	12
Eastern Europe	0	56	23	20	9	0	50	35	16	12
India	*	n/a	n/a	20	9	*	n/a	n/a	16	12
Japan	268	56	23	20	9	257	50	35	16	12
Korea	*	n/a	n/a	20	9	*	n/a	n/a	16	12
Mexico	*	n/a	n/a	20	9	*	n/a	n/a	16	12
Western Europe	130	56	23	20	9	139	50	35	16	12
United States	82	56	23	20	9	107	50	35	16	12
Rest of World	*	n/a	n/a	20	9	*	n/a	n/a	16	12

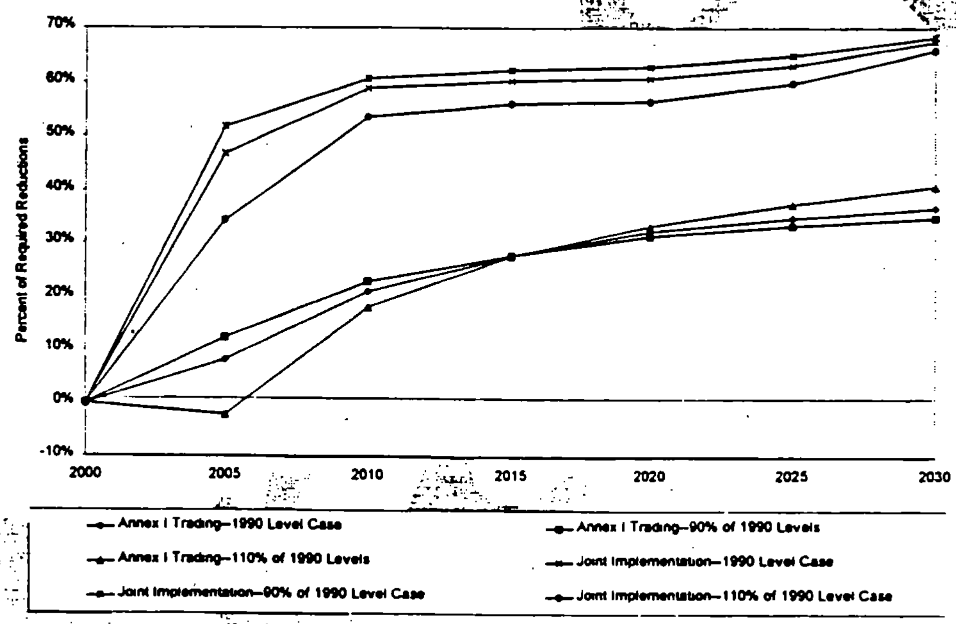
Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in C/GDP. * indicates the cell is blank because the country is a non-Annex I country. CR=corresponding reductions.

Under Annex I trading with "corresponding reductions," the implicit price of carbon falls dramatically--to $56 in 2010 and $50 in 2020. All countries gain through these lower permit prices, because as a whole they achieve stabilization at 1990 levels more cheaply. The source of these cheap emissions is the FSU and the Eastern European nations. The implicit price of carbon falls because it is cheaper for all of the industrialized nations to pay for carbon abatements in those nations (due to lax environmental standards and slow economic growth) than to pursue domestic options only. These nations gain as they become emissions permit sellers under Annex I trading. If "corresponding reductions" are not required, the FSU would be allowed to sell permits up to its 1990 level further depressing the price to $23 per ton in 2010 and $35 in 2020.

Under Annex I trading with "corresponding reductions," the United States purchases 72 million metric tons of permits from the FSU and Eastern Europe in 2010 at a cost of $4 billion ($95), which offsets $5 billion of abatement expenditures within the United States. U.S. purchases of permits abroad increases to 157 million metric tons of permits in 2020 at a cost of $7.8 billion, which offsets $12.2 billion of cost increases that would have occurred domestically if the U.S. did not participate in international trading.

Joint Implementation with developing countries reduce the costs of permit prices even further.
Joint implementation -- emissions trading on a global scale -- reduces the permit price further, to $20 in 2010 and $16 in 2020 (with corresponding reductions). If corresponding reductions are not required the implicit price of carbon falls to $9 in 2010 and $12 in 2020. Under this broader market for tradeable emissions permits the FSU and Eastern Europe lose their monopoly on permit sales. Specifically, Joint Implementation encourages China and India to reduce their use of coal and enter the market as emissions permit sellers. As shown in Figure 8, imports of carbon permits are greater under Joint Implementation than under Annex I trading.

Figure 8: U.S. Imports of Carbon Permits Under Alternate Mitigation Targets--Annex I Trading and Joint Implementation

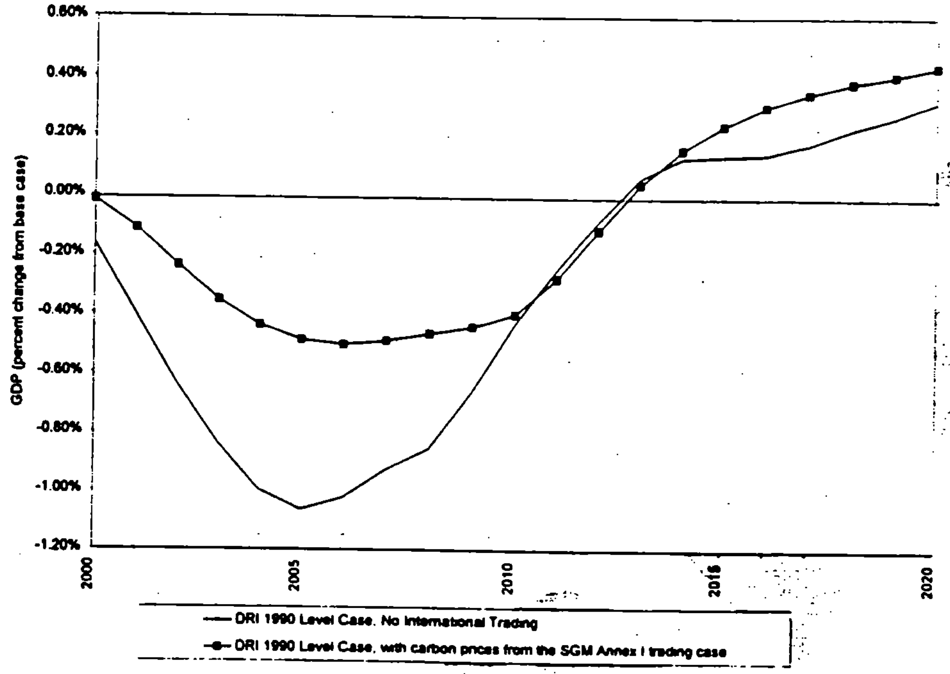


Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in C/GDP.

Using the SGM implicit carbon prices from Annex I trading to simulate macroeconomic conditions for the DRI Model moderates the short-term economic effects of emissions reductions.
The IAT incorporate Annex I implied permit prices estimated by the SGM model under permit trading, with corresponding reductions into the DRI model. For in 2010 SGM's Annex I trading implicit price of carbon estimate ($56) was incorporated into the DRI model.

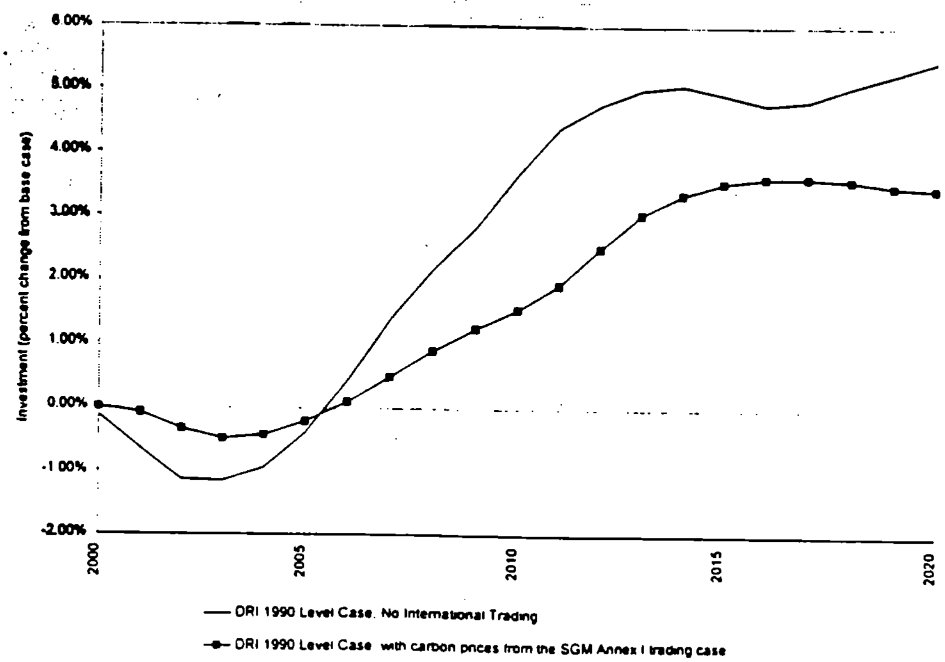
The results from the DRI model using the SGM permit trading implied permit prices are represented in Figures 9, 10, and 11. As shown in Figure 9, the maximum effect on GDP is less than half, 0.5 percent less than the baseline in 2006 compared with about one percent in 2005. The lower permit prices also has a somewhat dampening effect on the increase in investment under the no trading case, but shows a much improved effect on the impact on consumption, a -0.7 percent change in 2010 compared with a -1.4 percent change in 2008, and reaches the baseline consumption estimates in 2018.

Figure 9: DRI-DRI Energy 1990 Level Case with and without Annex I Trading--GDP



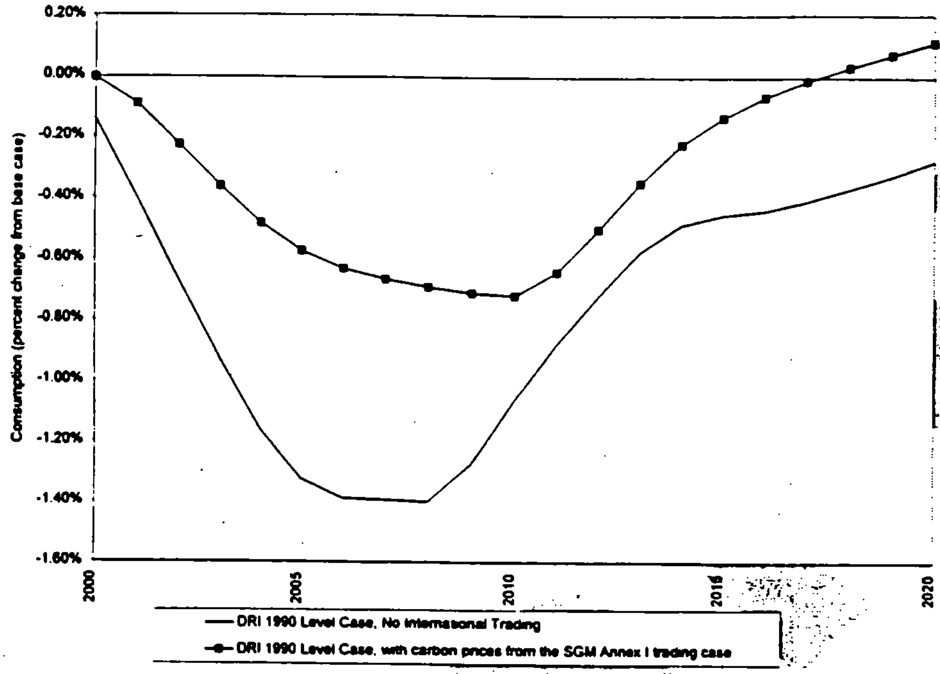
Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 10: DRI-DRI Energy 1990 Level Case with and without Annex I Trading--Investment



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 11: DRI-DRI Energy 1990 Level Case with and without Annex I Trading--Consumption



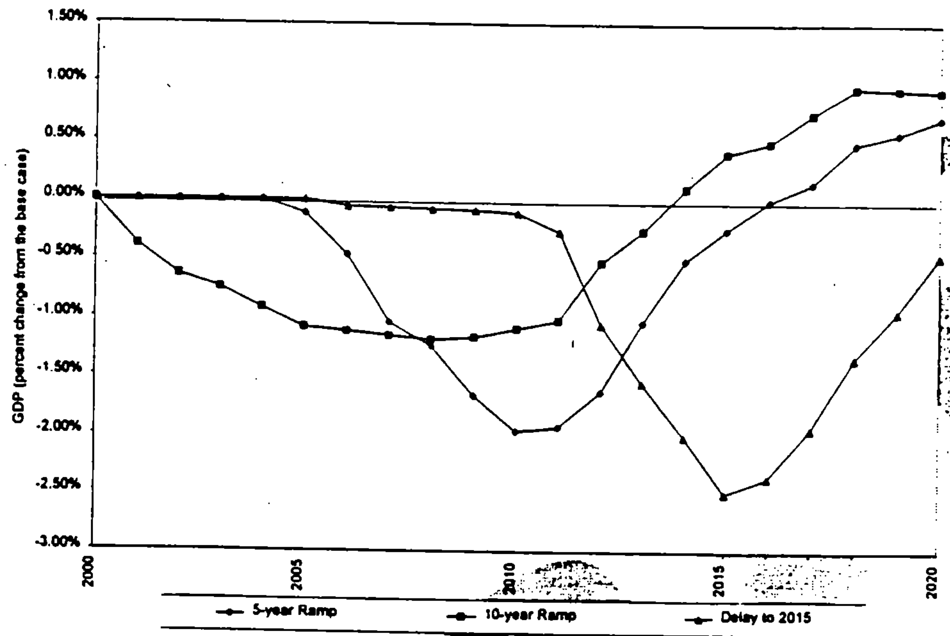
Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Important Sensitivities

The following represents a number of variations from the "starting point" scenario that the IAT analysts examined to address a number of factors that will influence the climate change policy process. These include the effects of: (1) timing, including different transition periods to full implementation and delaying implementation; (2) lower or higher emission level targets; (3) different revenue recycling options, including comparing the deficit reduction case with scenarios where revenues are distributed to consumers, distributed to business, and a combination of both consumers and business; (4) policy announcement on the rate if technological innovation and diffusion as well as the steps needed to achieve a higher level of innovation and diffusion; (5) other collateral environmental benefits; and (6) international trade; and (7) Federal Reserve reaction assumptions in the DRI model.

Increasing the implementation period from 5 to 10 years dampens the negative effects on GDP. Delaying implementation until 2015 does little to improve GDP effects. The IAT examined differing effects on GDP of a 5-year and a 10-year implementation period for the "starting point" scenario with the NEMS model. These results are shown in Figure 12. A 5-year ramp-up between 2005 and 2010 results in a maximum output loss in 2010 that is 65 percent greater than that associated with a ten year ramp-up and a return to the baseline two years later. Thus, shorter transition periods result in a more pronounced economic cycle in response to policy--a sharper downturn and deferred recovery.

Figure 12: NEMS 1990 Level Case, No International Trading-- Sensitivity to the Length of the Implementation Period and to Implementation Timing



Note: These simulations were conducted using DRI and the NEMS Energy Model and they do not conform in detail to those conducted using DRI and the DRI Energy Model. 5-Year and 10-Year Ramp to 1990 Levels in 2010; 1990 Levels in 2015 using a 5-Year ramp-up. Revenues are used for Federal deficit reduction, assuming 1.25 percent annual decrease in E/GDP.

Figure 12 also shows the result of delaying the implementation by 5 years, to 2015 combined with the shorter 5-year ramp-up period. GDP effects for the delayed case are less severe in the initial period, but become greater than either the 5-year or 10-year ramp-up to stabilization in 2010.

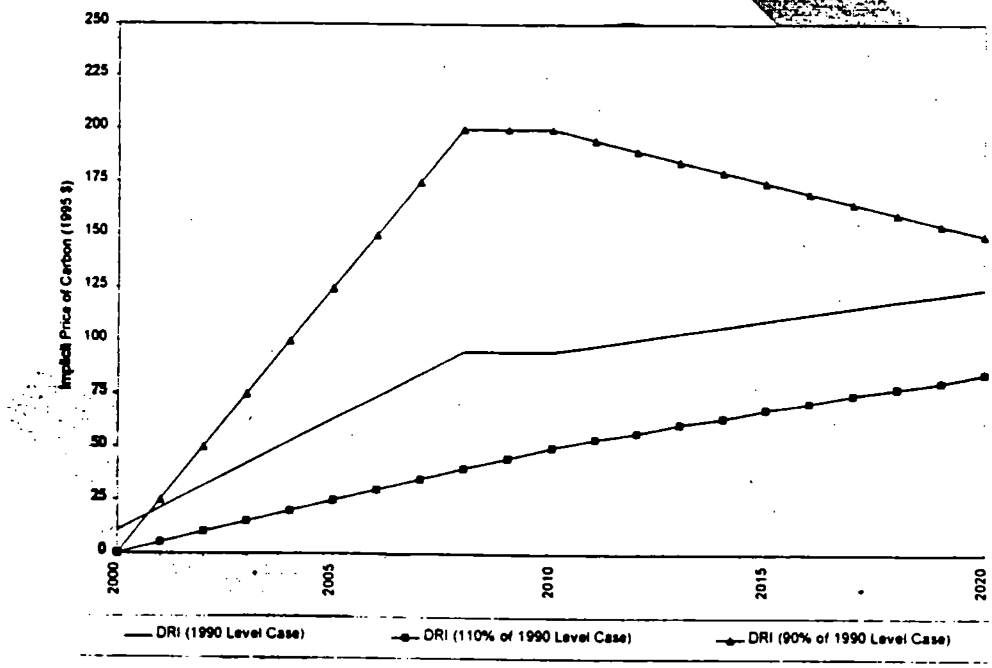
Raising or lowering emission targets lead to obvious results--more stringent emission targets lead to greater economic losses while less stringent ones have less severe impacts The three models were used to analyze how changes in the level of emissions affect the implicit price of carbon. If the emission target for the year 2010 and beyond is raised (made less severe) to a level equal to 110 percent of the 1990 emissions level (that is, to a target of 1,472 million tons as opposed to 1,338 million tons), then the DRI model estimated that the implicit price of carbon drop almost by half -- to about $50 per ton of carbon, while the SGM model dropped from $81 to $37. The very large decline in the implicit price of carbon reflects the fact that additional emissions reductions are progressively harder to find. On the other hand, a more stringent target, one that freezes emissions at 90 percent of their 1990 level in the year 2010 and beyond, leads to an implicit price of carbon of $200 per ton in 2010 and $150 per ton in 2020, according to the DRI model. The SGM model estimated that the implicit price of carbon would be $145 and $183 in 2010 and 2020, respectively. The implicit price of carbon generated by Markal-Macro for the 90 percent of the 1990 level case with no international trading would be $187 and $207 in 2010 and 2020, respectively. Table 9 and Figures 13 and 14 describe the sensitivity of these results using DRI, SGM, and Markal-Macro.

Table 9: Sensitivity of the Implicit Price of Carbon to the Stringency of the Emissions Target No International Trading

	2010	2020
DRI-DRI Energy		
Carbon Emissions 90% of 1990 Level Case	200	150
Carbon Emissions 110% of 1990 Level Case	50	85
SGM		
Carbon Emissions 90% of 1990 Level Case	145	183
Carbon Emissions 110% of 1990 Level Case	37	56
Markal-Macro		
Carbon Emissions 90% of 1990 Level Case	187	207
Carbon Emissions 110% of 1990 Level Case	101	93

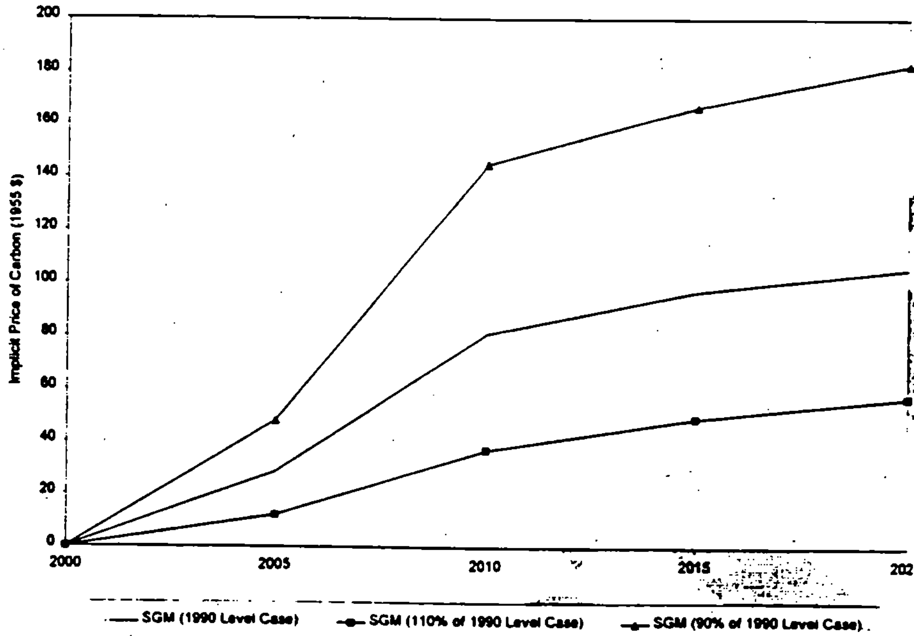
Note: 10 year phase-in with revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP. SGM uses a similar rate of change in C/GDP.

Figure 13: DRI-DRI Energy No International Trading--Sensitivity of the Implicit Price of Carbon to the Stringency of the Emissions Target



Note: 10 year phase-in with revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 14: SGM No International Trading--Sensitivity of the Implicit Price of Carbon to the Stringency of the Emissions Target



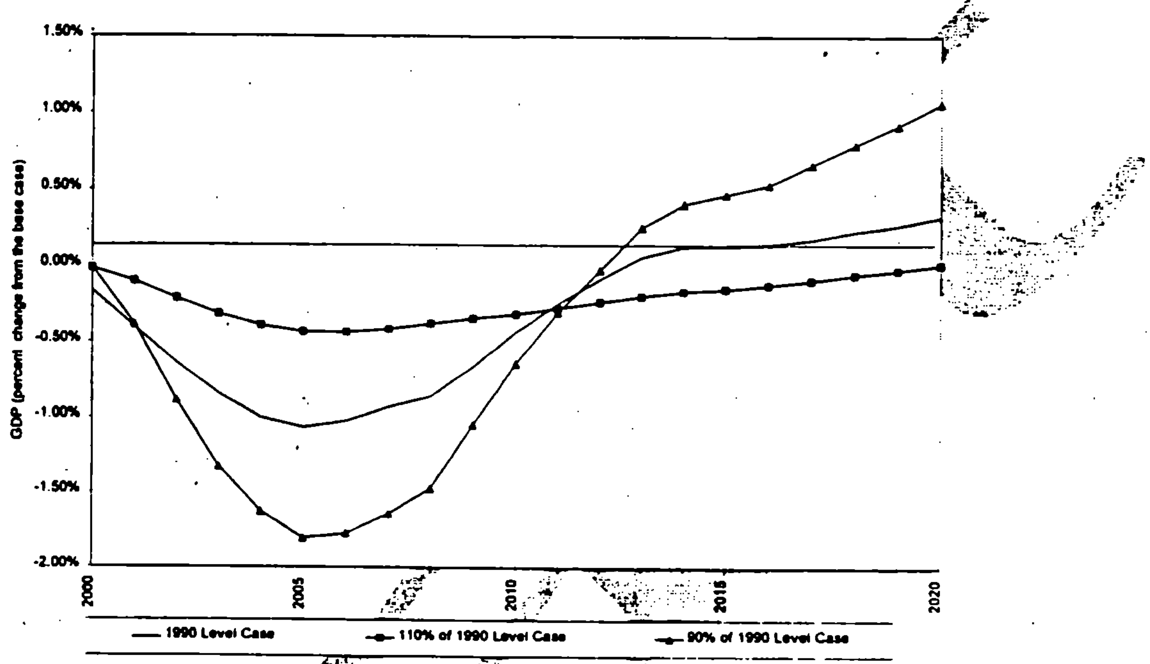
Note: 10 year phase-in with revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in C/GDP.

In 2020, permit prices rise to about $85 compared with the $125 permit price under stabilization. Using the DRI model, an emissions target of 90 percent of 1990 level results in an implicit price of carbon of $200 per ton in 2010 and $150 in 2020. Unlike in the other cases, the implicit price of carbon falls after 2010. This is because the initial price increase is large enough to set in motion a series of capital stock improvements, particularly in utilities, that reduce the ongoing level of emissions by enough to allow the implicit price to fall in the future. Thus, this result is predicated on the idea that future price expectations could be wrong. In fact, if decision makers had perfect price expectations, the implicit price of carbon would lie somewhere between these two values over the period.

It is no surprise that the 90 percent of 1990 emissions case results in a more severe decline of GDP in the transition period. But what is surprising, and questionable, is that this scenario also has a greater long-term potential for economic recovery. As shown in Figure 15, GDP declines to a peak loss of 1.9 percent below the base case in 2005. It recovers to the base case level in 2013 and increases to 1.0 percent above the base case in 2020. The long-term rebound effect results from a greater amount of revenue used for deficit reduction (or debt retirement), which pushes interest rates down substantially and drives up investment. The magnitude of this result is questionable.

The DRI model, as discussed, is prone to depicting large effects of interest rates on investment. Thus, when confronted with a very large implicit price of carbon and, in turn, large amounts of forced saving, either through deficit reduction or by grandfathering these new property rights to firms, it produces much higher levels of investment and a higher long-term growth path. The reality is probably more moderate at both ends. In essence, this case appears to tax the ability of the model to manage these revenue flows.

Figure 15: DRI-DRI Energy No International Trading--Sensitivity of GDP to the Stringency of the Emissions Target



Note: 10 year phase-in with revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

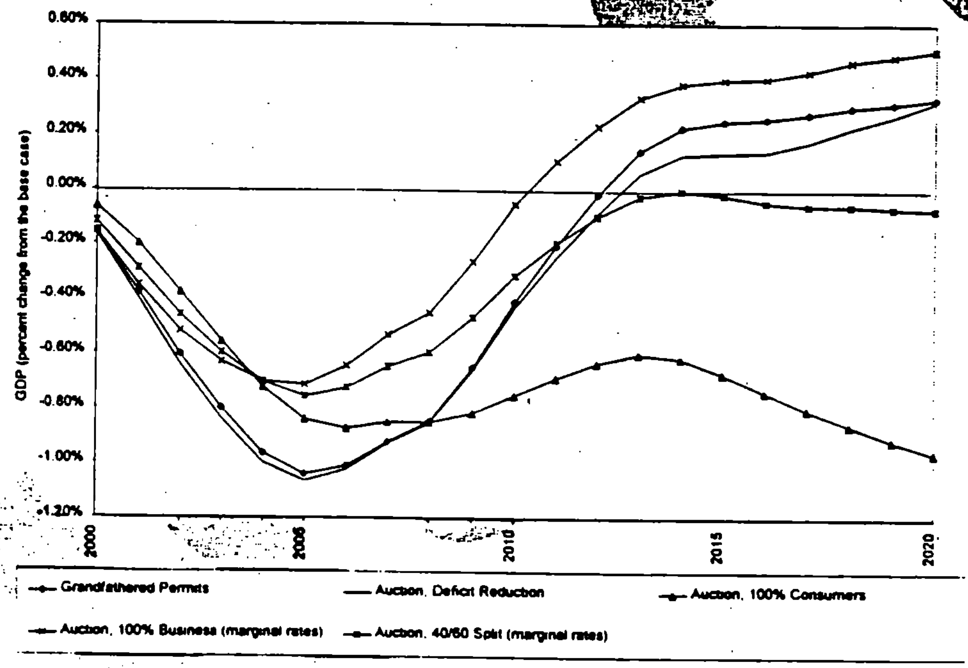
The portion of total emission reductions from coal and oil in both the 90 percent and 110 percent of 1990 Level Case, No International Trading, increases only slightly--about 5 percentage points--while total emission reductions from natural gas change significantly. In 2010, under stabilization, about 13 percent of total emission reductions are from natural gas. Under a 10 percent increase in the target (that is, a target of 90 percent of 1990 emissions), about 9 percent of total emission reductions are from natural gas. This occurs because the substitution of gas for coal in electric utilities is not enough to achieve the bulk of the 90 percent (more stringent) target. Additional emissions reductions must be found, which forces the burden to be spread more evenly among fuel types and sectors.

Adopting a revenue recycling option that favors capital formation leads to less impact on the economy during the transition and greater returns to the economy in the long term. The IAT looked at a number of revenue recycling policies in addition to the deficit reduction case. These options are depicted in Figure 16. These include:

- "grandfathering" permits to producers, meaning that every carbon-emitter would be given sufficient permits to allow them to emit at their 1990 level. The permits allowing them to do so would then be traded freely, allowing a least-cost response to the problem to emerge;

- a 100 percent recycling of any revenues from permit auctions to consumers through a reduction in the personal income tax;
- a 100 percent return to business through a reduction in the marginal rates of the corporate income tax; or
- a 40/60 split to consumers and businesses, in proportion to their shares of energy use, through tax rate reductions.

Figure 16: DRI-DRI Energy 1990 Level Case, No International Trading--Sensitivity of GDP to Revenue Recycling Options



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Assuming a 1.25 percent annual decrease in E/GDP.

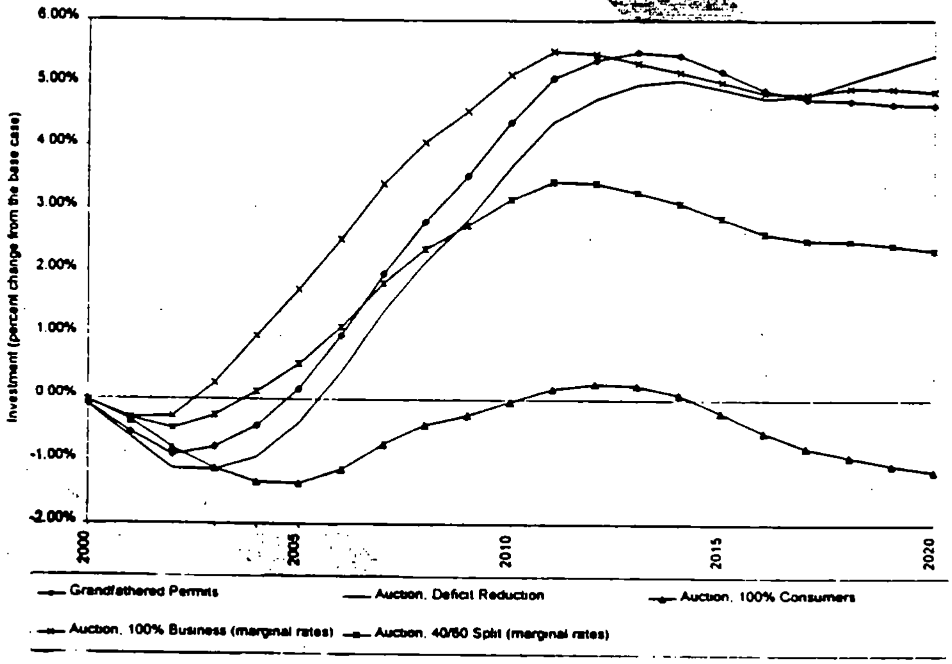
According to the IAT analysis, the revenues generated from the implementation of this policy have the most positive effect when returned through either the deficit reduction plan, grandfathered permits, or to business through lower taxes. Revenue recycled to consumers, in either case, result in a greater and longer-term reductions in GDP, when measured against the baseline, but would have correspondingly lower impacts on consumption.

The revenue recycling options that lead to better economic outcomes are all those associated with greater investment and capital formation. Deficit reduction leads to lower interest rates, which lowers the cost of capital and facilitates investment. Recycling revenues to companies has the effect of increasing savings through apparent profits and provides the wherewithal for greater investment spending. Similarly, grandfathering permits to producers allows them to "assetize" their right to produce emissions. This allows firms to realize gains on this "right" and again provides the wherewithal to invest.

Peak GDP losses during the transition period are less severe for the 100 percent to business and 40/60 split when accomplished through reductions in the marginal tax rates, (about 0.7 percent in 2005), compared with the other recycling options, (between 0.8 and 1.0 percent in that year).

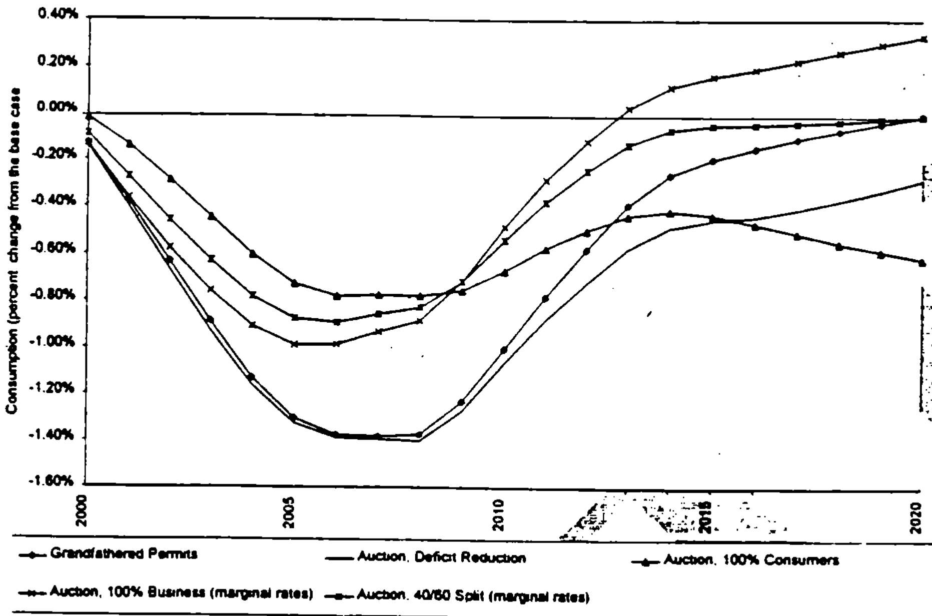
Figures 17 and 18 demonstrate the effects of revenue recycling on investment and consumption, in relation to the effect on GDP, as shown in the previous figure. As these figures show, the key to economic recovery among the revenue recycling options is to improve investment in the economy.

Figure 17: DRI 1990 Level Case, No International Trading— Sensitivity of Investment to Revenue Recycling Options



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Assuming a 1.25 percent annual decrease in E/GDP.

Figure 18: DRI-DRI Energy 1990 Level Case, No International Trading-- Sensitivity of Consumption to Revenue Recycling Options

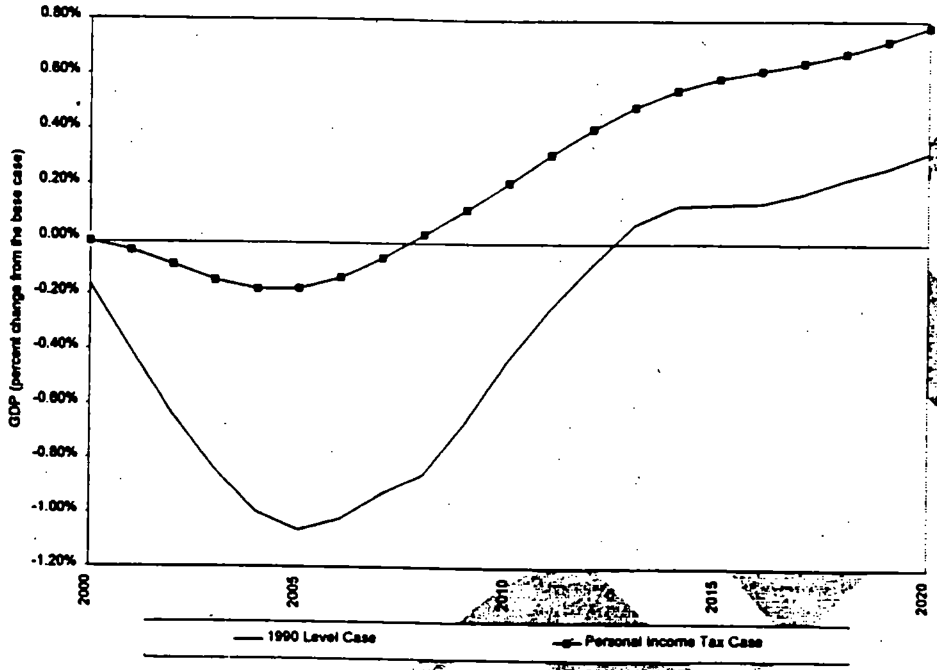


Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Assuming a 1.25 percent annual decrease in E/GDP.

But the economic effects of these recycling options must be separated from the economic effects of carbon limitations *per se*. That is, economic analysis can make the case -- and models are often structured to demonstrate -- that reducing taxes on capital could improve long-term economic performance. In order to separate these effects, the 1990 emissions freeze accompanied by the use of any permit auction revenues to reduce the deficit was compared to a conventional increase in the personal income tax to achieve a comparable level of deficit reduction.

An increase in the personal income tax results in smaller economic losses and a more prompt economic rebound than a "deficit-equivalent" carbon reduction policy, as shown in Figure 19. Thus, while revenue recycling options can affect significantly the outcome of a carbon-reduction policy, the gains they create are unrelated to carbon reduction itself.

Figure 19: DRI-DRI Energy, No International Trading--Comparison of GDP, Recycling Revenue Recycling through Deficit Reduction and a Personal Income Tax Increase



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Assuming a 1.25 percent annual decrease in E/GDP.

Technological progress can be very helpful, especially in the long term. In its analysis of technology, the Markal-Macro model was used to determine whether higher levels of energy to GDP (E/GDP) savings are realistic. This analysis assumed two benchmarks for technological progress. In the first, the annual steady-state improvement in the economy's efficient use of energy was increased from the level of 1.0 percent in the AEO97 projections (found in the "no policy" base case) to a level of 1.25 percent. In the second case, this improvement in energy efficiency was increased to 1.75 percent. These two benchmark levels were obtained by examining the historical record and engineering estimates of potential technical progress. The point of the analysis was then to determine not only what effect technical progress might have on the economic effects of climate change policy, but also whether these rates were themselves technically feasible.

According to results from the Markal-Macro model, an improvement in the energy intensity of 0.25 percent annually, or a total annual decline of 1.25 in energy per unit of real output, can be achieved without great difficulty using both off the shelf technologies as well as new technologies that are near commercial viability. For example, such an improvement can be produced if the "hurdle rates" -- that is, the premium that households and firms appear to place in their discount rate when considering energy-efficiency investments -- declines by 81 percent. For example, the discount rate households use when considering installing better insulation would have to fall from 46 percent to 23 percent). Thus, this improvement can be achieved through diffusion practices even without assuming a higher rate of innovation and technological progress. In fact, some analysts believe that the enactment of the CCAP gets us to the 1.25 annual reduction.

The Markal model demonstrates that the higher technological case -- an increase in the annual rate of improvement in energy-efficiency of 1.75 percent -- is more difficult to achieve. Specifically, this higher level of energy savings cannot be achieved through better diffusion of best technical practices alone. Thus, new innovation must occur if we are to move beyond the 1.25 case. To achieve the 1.75 case, a new set of advanced energy efficiency technologies was added to the pool of technologies. These are part of the DOE research portfolio. Some of these technologies are aggressive in their scope: For example, the average fuel efficiency of new cars entering the vehicle fleet in the year 2020 is 33 miles per gallon in the 1.25 case, but rises to 55 miles per gallon for new cars entering the vehicle fleet in the 1.75 case. They were all deemed viable in an outside peer-review of the DOE program. The IAT will be circulating the technological assumptions necessary to achieve this 1.75 benchmark in a separate paper.

Rather than use the specific technological assumptions developed in Markal, the IAT represented technological progress in the DRI model by targeting a 1.75 percent annual rate of energy improvement in the economy for supply and end-use technologies in all sectors. For residential and commercial sector space heating/cooling and water heating, DRI assumed improved performance and cost characteristics for various heating and cooling equipment types and allowed the model to choose the optimal technologies. The model selects equipment based on life-cycle cost estimates, which include a "first-cost bias" that weights up-front capital costs more heavily than future fuel costs. This is comparable to the higher discount rates used in Markal.

For all other residential and commercial sector energy end-uses, the DRI model uses estimates of the average efficiency of all new and retrofit equipment purchases to determine fuel use requirements. These average efficiencies were increased to reflect improvements to technology performance and higher rates of diffusion for more efficient technologies. No changes were made to the rates of capital stock turnover and replacement.

Table 10 summarizes the effects of higher technological progress (that is, the 1.75 percent annual rate versus the 1.25 annual rate) on the economic effects of carbon-limiting policies. As seen, higher rates of technological progress can dramatically cut the implicit price of carbon and the associated transitional GDP losses. In the IAT "starting point" case (assuming 1.25 percent annual efficiency improvements), the implicit price of carbon in the three models is \$95, \$81 and \$145 per ton in 2010 and \$125, \$106 and \$130 per ton in 2020, for DRI, SGM, and Markal-Macro respectively. In the more advanced technology case, the implicit price of carbon is \$88, \$53, and \$77 per ton in 2010 and \$30, \$51, and \$35 per ton in 2020, for DRI, SGM and Markal-Macro respectively.[4]

[4] SGM applied the rate of carbon-efficiency for purposes of modeling technological improvement in energy-efficiency because it is easier for SGM to manage C/GDP than E/GDP. Carbon to GDP is an equally appropriate target and the differences in the results of the two specifications is not large.

Table 10: Sensitivity of Implicit Price of Carbon (1995$) to Rate of Technological Change --1990 Level Case, No International Trading

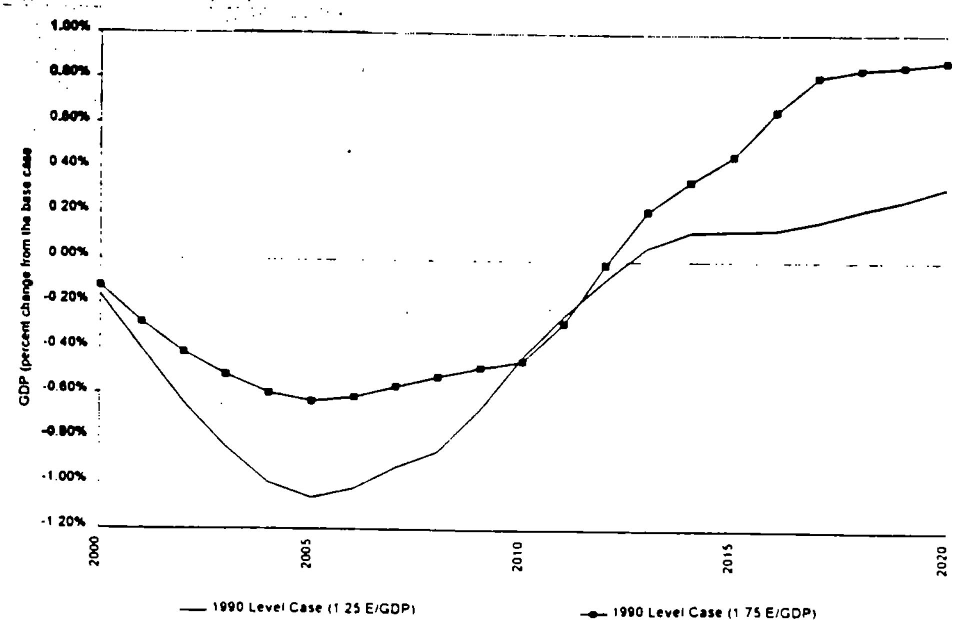
	2010		2020	
	1.25 Case	1.75 Case	1.25 Case	1.75 Case
DRI-DRI Energy	95	88	125	30
SGM	81	53	106	51
Markal-Macro	145	77	130	35

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for deficit reduction. DRI permit prices are generated using the annual rate of change in E/GDP. SGM uses a similar rate of change in C/GDP.

The peak GDP losses change accordingly, as shown in Figure 20. Using the DRI model, the peak output loss of -0.6 percent occurs in 2005, and the economy reaches its pre-policy growth path by 2012. The economy's shift to a higher growth path is also more pronounced, but here the result is more believable, because it is achieved through technological progress rather than revenue recycling that raises savings and fosters investment (in fact, the level of revenue recycling falls dramatically along with the implicit price of carbon).

The risk, however, is that these output gains may be somewhat overstated, because they do not account for the cost of the investments needed to reach the higher rate of technological progress. For example, firms will have to perform R&D that might distract them from other R&D tasks. If other R&D in the economy fell as energy- and carbon-related R&D was performed, overall productivity could drop and offset the economy's potential growth elsewhere. Alternatively, firms might increase total R&D effort, but leave the economy with fewer resources to do other things. While it is likely that these effects are second-order when compared to the effects of the improvement in carbon-related efficiency, they are still absent from the analysis.

Figure 20: DRI-DRI Energy 1990 Level Case, No International Trading--Sensitivity of GDP to the Rate of Technological Progress



Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues used for deficit reduction

These results indicate how important technological progress especially in the long term. A substantially higher rate of technological progress will improve short-term results. But it is capable of moving the analysis significantly once its effects are allowed to accumulate.

Reducing carbon emissions would also reduce other pollutants leading to direct economic benefit. The release of CO_2 is inherent in the activity of burning fossil fuel under current technologies. When CO_2 emissions in the utility, industrial boiler, and transportation sectors are reduced--either by using less fuel or by altering the mix of fuels--emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) are also reduced. In the atmosphere, NO_x and SO_2 react with ammonia to form ammonium nitrate and ammonium sulfate--significant components of fine particulate matter ($PM_{2.5}$), which may cause significant respiratory health problems and mortality.[5]
To investigate this effect, the NEMS model was used to estimate SO_2 and No_x emissions from electricity generation. When emissions are frozen at 1990 levels without trading, NEMS estimates decreases in utility NO_x and SO_2 emissions of 60 percent 47 percent, respectively in 2010.

The NEMS model provided emissions for each of the thirteen NERC regions. These results were then translated into disaggregated county level emissions by calibrating the NEMS results to the county specific data from EPA's National Particulate Inventory. The results were then fed through EPA's climatological regional dispersion model, which calculates the resulting air quality changes for each county. Finally, these results were used to estimate health and welfare effects of air pollution using EPA methodology developed under Section 812 of the Clean Air Act Amendments and reviewed and endorsed by EPA's Science Advisory Board.

Health benefits from reducing utility NO_x and SO_2 emissions in the "starting point" stabilization case include avoided mortality, avoided cases of chronic bronchitis, reduced acute bronchitis, fewer upper and lower respiratory symptoms, and a decline in lost work days. The results are very sensitive to the value attributed to avoided mortality, here estimated at $5 million per episode. When monetized these benefits could have a mean value of over $4 billion per quad of coal based energy generation. Assuming the estimated 7 quad reduction found by DRI (in Table 4), this would yield benefits of about $30 billion.

NOTE TO READERS: The IAT has not yet quantified the NO_x and SO_2 emission reductions from the industrial and transportation sectors or estimated the reduction in emissions of other criteria air pollutants--e.g., carbon monoxide and volatile organic compounds.

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[5] This analysis assumes that no new regulations to control criteria air pollutants would be implemented at he Federal or state level. It is important to note that actions are being considered at the Federal and state levels, including proposed new National Ambient Air Quality Standards, the Clean Air Policy Initiative, and new State Implementation Plans, that could reduce NO_x and SO_2 emissions from utilities over the next decade independently of controlling CO_2 emissions.

The losses experienced by the United States by handicapping energy-intensive industries in international trade need not be large. There is widespread and legitimate concern that forcing an implicit energy price increase on U.S. producers will disadvantage them substantially through trade, particularly with those countries outside of Annex I that might not be subject to the same emissions limits. The IAT used the DRI model to examine the overall trade implications of such a possible energy price differential. Industry trade results are discussed in the Industry Results section of this report.

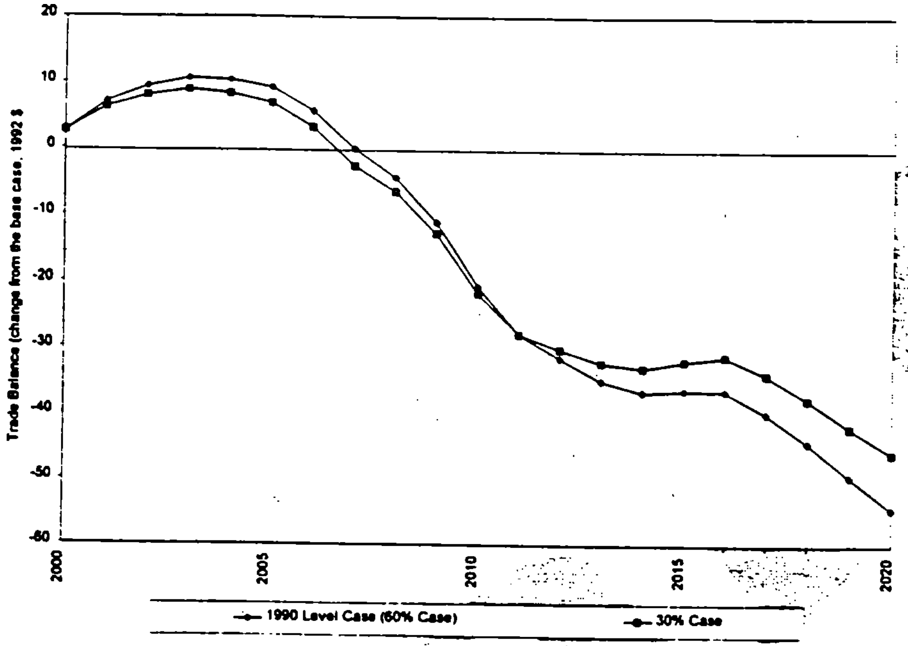
The DRI model examines overall trade effects by assuming a rate at which producers who export to the U.S. experience cost increases. In the aggregate, about 60 percent of imports of manufactured goods come from Annex I countries that will also experience higher implicit carbon prices (and, therefore, energy prices). The DRI model, therefore, assumes that manufactured imports, in general rise by an average of 60 percent of the full cost increase experienced by U.S. manufacturers.

This assumption, however, can be criticized as being too favorable to U.S. producers. If exporters from non-Annex I countries do not experience the cost increase that Annex I producers do, then they will no doubt substitute their production for Annex I production. Given this likely switching of export sources, the DRI model was also run with the assumption that foreign producers experience a cost increase equal to, on average, 30 percent as opposed to 60 percent of the U.S. cost increase.

Figure 21 presents the results under these two cases. The effect of the carbon-limiting policy on trade is depicted in these runs as surprisingly small. Some of the change in trade flows is reconciled in the DRI model by allowing the exchange rate to move, but as seen in Figure 22, the anticipated changes in the exchange rate themselves are not large and do not vary between the two assumptions. The small differences are not necessarily counterintuitive. There are already substantial energy price differences and differing environmental restrictions among trading nations that are larger than the price increase that results from the policies considered here.

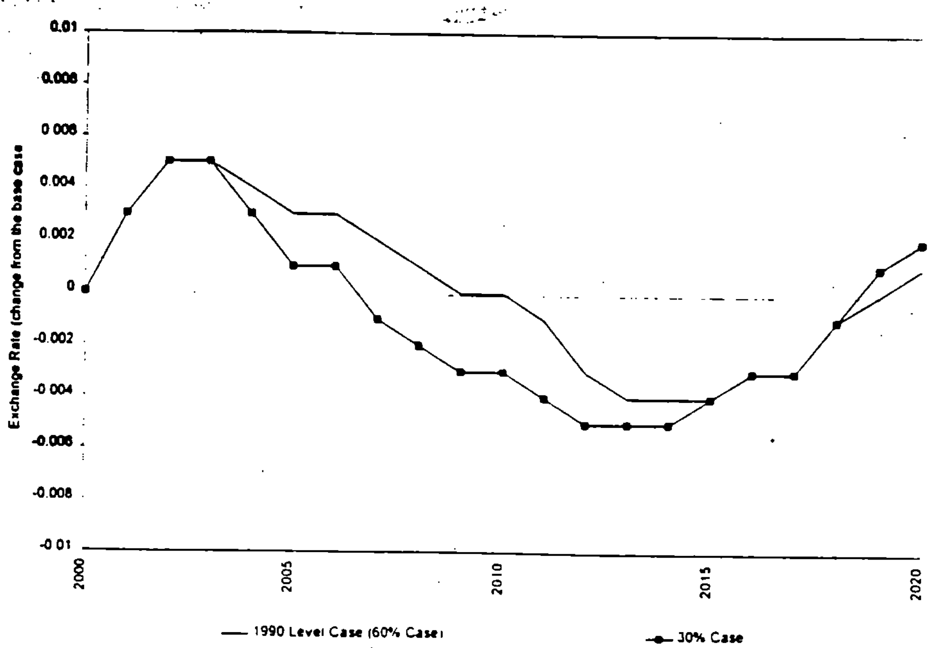
This aggregate treatment does not capture the effects that might be borne by specific industries due to their varying energy intensities. This more detailed examination is presented in Table 13, in the section on industry effects

Figure 21: DRI-DRI Energy 1990 Level Case, No International Trading--Sensitivity of the Trade Balance to International Price Ratio Assumptions



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 22: DRI-DRI Energy 1990 Level Case, No International Trading--Sensitivity of the Exchange Rate to International Price Ratio Assumptions



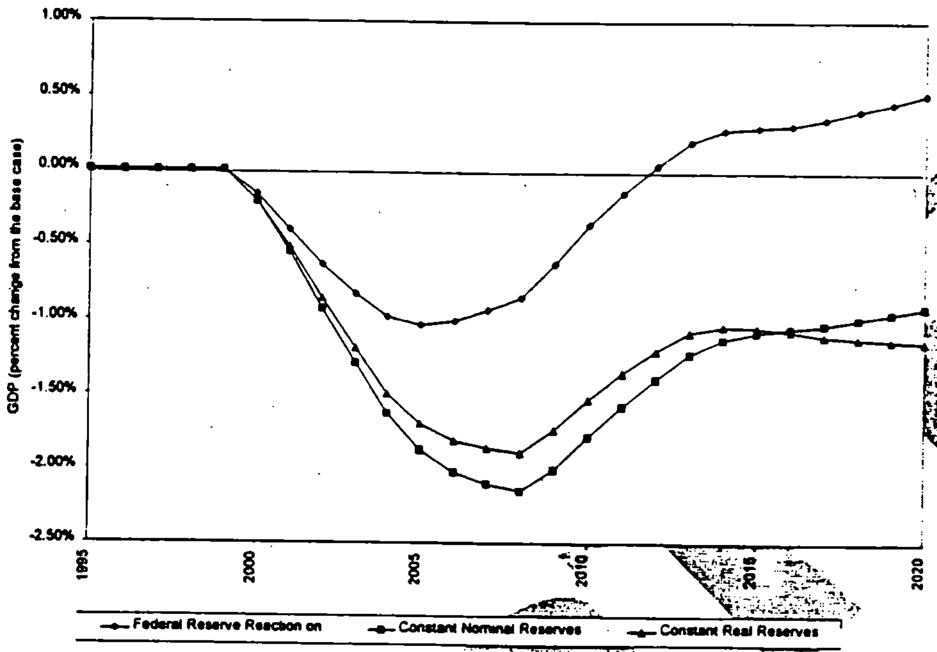
Note: Emissions stabilized at 1990 levels in 2010. Revenues used deficit reduction and assuming a 1.25 percent annual decrease in E/GDP

Alternative views about Federal Reserve policy can yield significantly different results. The Federal Reserve reaction function in the DRI model is an empirically derived estimation of likely Federal Reserve policy responses to changes in price inflation and the unemployment rate, among other variables. It is seen by DRI as the best proxy for Fed decisions in the model simulations. In essence, the reaction function will abate unemployment unless doing so would lead to high rates of inflation. This reaction function was used in the analysis as the default setting for the assessment of the alternative target profiles and implementation strategies. This section reports on a set of sensitivity analyses which consider different Federal Reserve actions: maintaining *nominal* non-borrowed reserves at baseline levels, and a case where *real* non-borrowed reserves are held at baseline. As can be seen from Figure 23, the effects of the alternative monetary policy assumptions are substantial.

If the Federal Reserve maintains nominal reserves at baseline, the size of the GDP loss is approximately doubled, from a 1 percent peak loss when the reaction function is on to just over 2 percent peak loss when more restrictive policies are pursued. There is essentially no difference between holding nominal non-borrowed reserves constant and holding real non-borrowed reserves constant. (The level of non-borrowed reserves in the banking system is an important Federal Reserve policy. If the Fed chooses to hold nominal reserves constant, then the funds that banks have to lend goes down when inflation rises. If real reserves are held constant, banks can lend more if prices go up.)

The sensitivity cases presented here, however, focus only on using the collected funds to reduce the federal deficit. The lower deficit (or greater surplus) makes it easier for the Fed to ease credit conditions without making inflation worse (indeed, as shown in Figure 5 inflation subsides by 2009 and inflation thereafter is lower than in the base case).The Federal Reserve can therefore do much to ease the economic transition in such an environment. But, the impact of the Federal Reserve reaction function fundamentally depends on how revenue recycling policy affects price inflation and the unemployment rate. In cases where price inflation remains high and unemployment losses are lower, the reaction function would ease credit conditions at a slower rate, and the divergence between the reaction function results and the nominal reserves at base case may be much smaller.

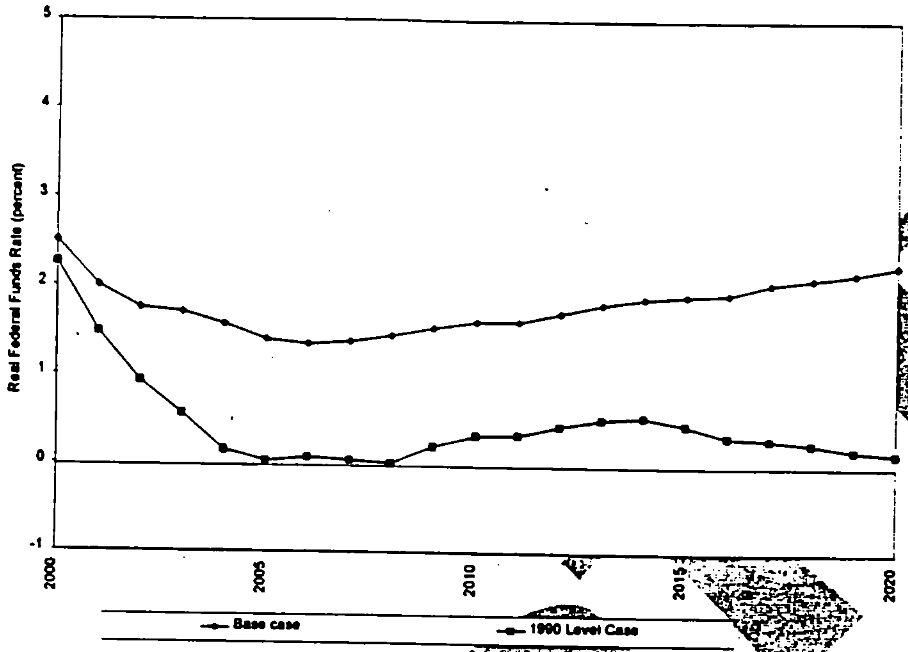
Figure 23: DRI-DRI Energy, No International Trading-- Sensitivity of GDP to Federal Reserve Policy Assumptions



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

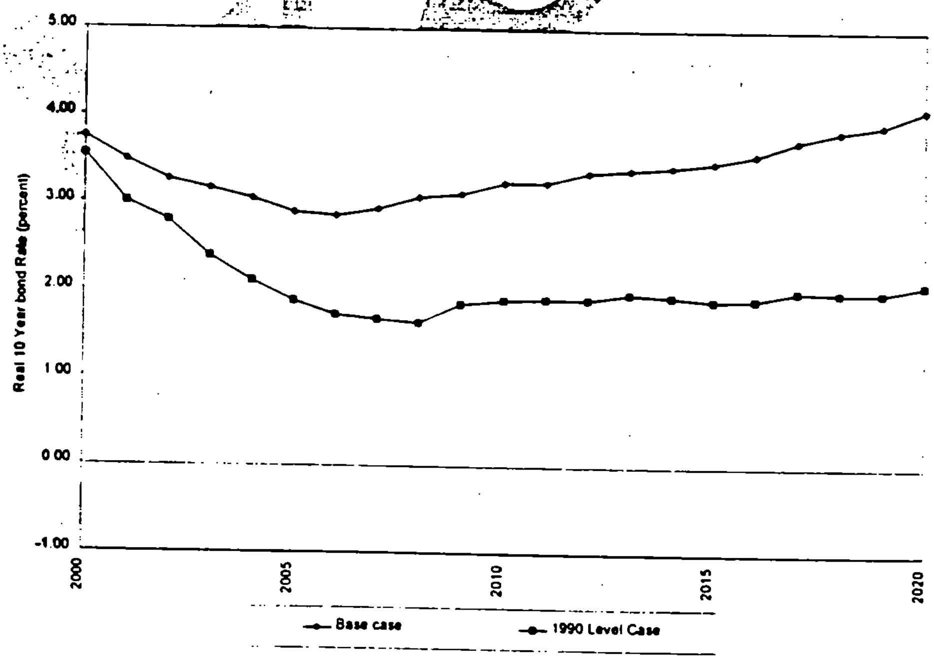
Figures 24, 25, and 26 show projections of the Federal Funds Rate, the 10-year Long Term Bond Rate, and the Federal Deficit/Surplus, respectively, from the DRI model with the Federal Reaction Function used in the analysis of the 1990 Level Case, No International Trading ("starting point"). These results show how important the treatment of revenue flows is in the DRI model. Substantial declines in the deficit (these runs were produced before the agreement to balance the budget in 2002 was achieved in May) allow interest rates to fall, which is the key to the economy's investment response.

Figure 24: DRI-DRI Energy 1990 Level Case, No International Trading-- Real Federal Funds Rate



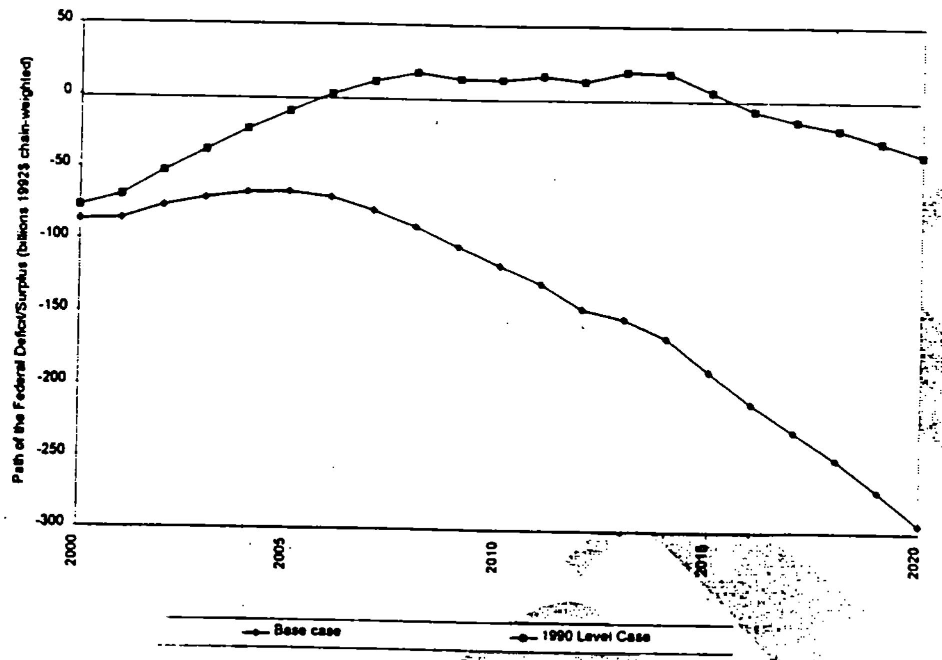
Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 25: DRI-DRI Energy 1990 Level Case, No International Trading-- Real 10 Year Long-Term Bond Rate



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 26: DRI-DRI Energy 1990 Level Case, No International Trading--Path of the U.S. Federal Deficit/Surplus



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

The results presented in the sections below on "Industry Results" and "Regional and Employment Effects" do not include cross-border emissions trading. The IAT is in the process of generating industry and regional results based on using implicit carbon prices from SGM Annex I trading results to simulate macro economic conditions for the DRI model, which will extend the final section of the core results to the industry and regional levels.

Industry Results

Using the DRI model, the IAT examined both the industry impacts and the impacts to regional employment associated with carbon-limiting policies. Regional impacts are discussed in the next section of the report. Table 11 provides impacts to the energy producing industries and to industries that are considered to be energy intensive. Table 12 lists the industries with the greatest increase from base case output and the largest decline from base case output in 2010.

Different energy models place different emphasis on three strategies for coping with energy price increases, with corresponding differences in projected fossil fuel impacts. These strategies include increased end-use efficiency, reduced end-use activity, or fuel-switching towards an increased market share of low- and no- carbon fuels. Increased end-use efficiency or reduced end-use activity tends to lower overall fuel demand, while fuel-switching favors low- and no-carbon fuels, such as natural gas and renewable energy, relative to high carbon fuels such as coal.

The DRI energy model results (reported here) emphasize improved efficiency and reduced end-use activity. In this model, stabilization reduces the use of all fossil fuels (coal, oil, and natural gas) relative to baseline levels. In contrast, for example, the NEMS results rely more heavily on fuel switching opportunities in the utility and transportation sectors, as well as efficiency improvements in cars. The NEMS stabilization runs show greater reductions in coal use than the DRI runs, but natural gas use actually increases relative to baseline due to fuel switching and a higher level of end-use energy demand.

Table 11: DRI-DRI Energy 1990 Level Case, No International Trading Impact on the Output of Energy Producing Industries and Energy Intensive Industries (percent change from the base case)

	2010		2020	
	No trading	With International Trading	No trading	With International Trading
Energy Producers				
Electric Utilities	-11.6%	n/a	-17.7%	n/a
Petroleum Refining	-8.8%	n/a	-9.3%	n/a
Coal Mining	-25.9%	n/a	-39.3%	n/a
Natural Gas	-19.9%	n/a	-18.2%	n/a
Gas Utilities	-11.4%	n/a	-10.9%	n/a
Crude Petroleum	-11.8%	n/a	-12.4%	n/a
Fuel Oil	-13.6%	n/a	-16.7%	n/a
"Pipelines. ex. Natural Gas"	-7.8%	n/a	-8.0%	n/a
Energy Intensive Industries				
Food and Kindred Products	-0.9%	n/a	0.2%	n/a
Chemical and Allied Products	-1.9%	n/a	-1.6%	n/a
Petroleum and Coal Products	-9.2%	n/a	-10.0%	n/a
Stone. Glass. and Clay Products	0.8%	n/a	2.3%	n/a
Paper and Allied Products	-0.6%	n/a	0.4%	n/a
Primary Metals	-1.0%	n/a	-1.0%	n/a

Note: Emissions stabilized at 1990 levels in 2010 with a 10 year phase-in. Revenues are used for Federal deficit reduction. assuming a 1.25 percent annual decrease in E/GDP. Estimates for the international trading scenario are forthcoming.

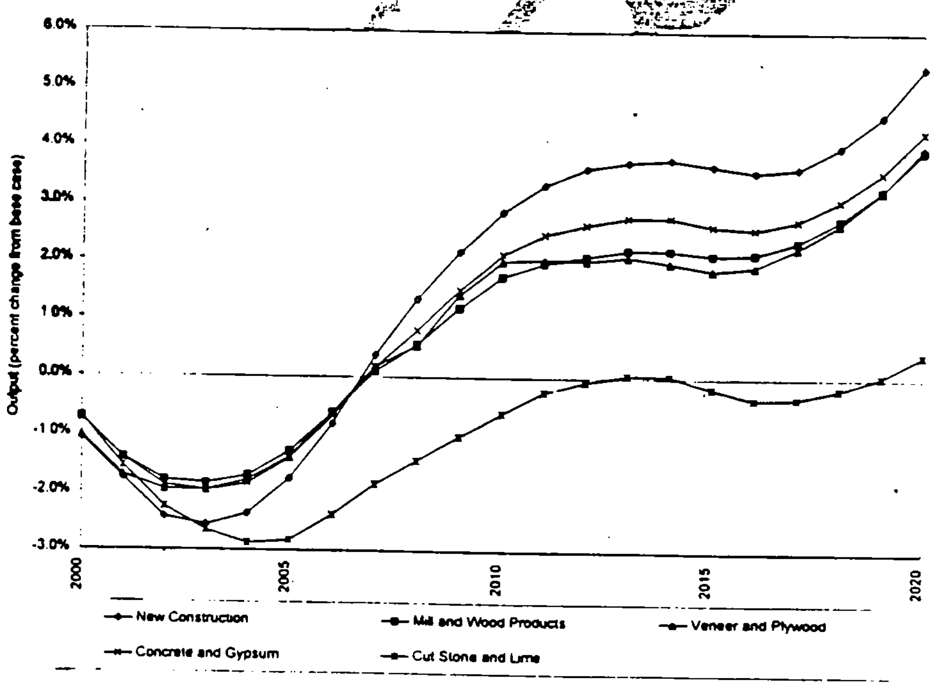
Energy intensive industries are put at a disadvantage by higher implicit prices for fossil fuels following the imposition of policy. This occurs because they are displaced through trade -- an effect that DRI depicts as relatively minor -- or because the composition of the economy's output changes in favor of less energy-intensive goods and services. These composition shifts drive the industry results. For some industries, however, composition may shift in favor of energy intensive industries because the economy's composition shifts from consumption to investment. which calls up a different mix of goods itself.

For example. a number of energy intensive manufacturing and construction sectors benefit in the long-term by the stimulus to investment created by the reduction of the deficit. Table 12 shows that 6 of the top 10 industries. in terms of output increasing above the base case. are directly or indirectly related to construction. which reflect the increase to the investment component of the economy. Figures 27 and 28 show the short-term output losses and the long-term output gains of a number of these industries.

On the other hand, industries whose production is used primarily for consumption, particularly energy products such as petroleum and coal, but also including paper, chemicals, and food and kindred products, continue to show losses in annual output. The energy producing industries show losses in output from between 8 percent for pipelines and 26 percent for coal mining. Consumer non-durable goods producing industries show losses of output that ranges from 1 percent for food processing to 10 percent for rubber and plastic footwear. In the longer-term, other than the energy producers, the consumption-oriented industries are expected to just about reach their output levels in the baseline.

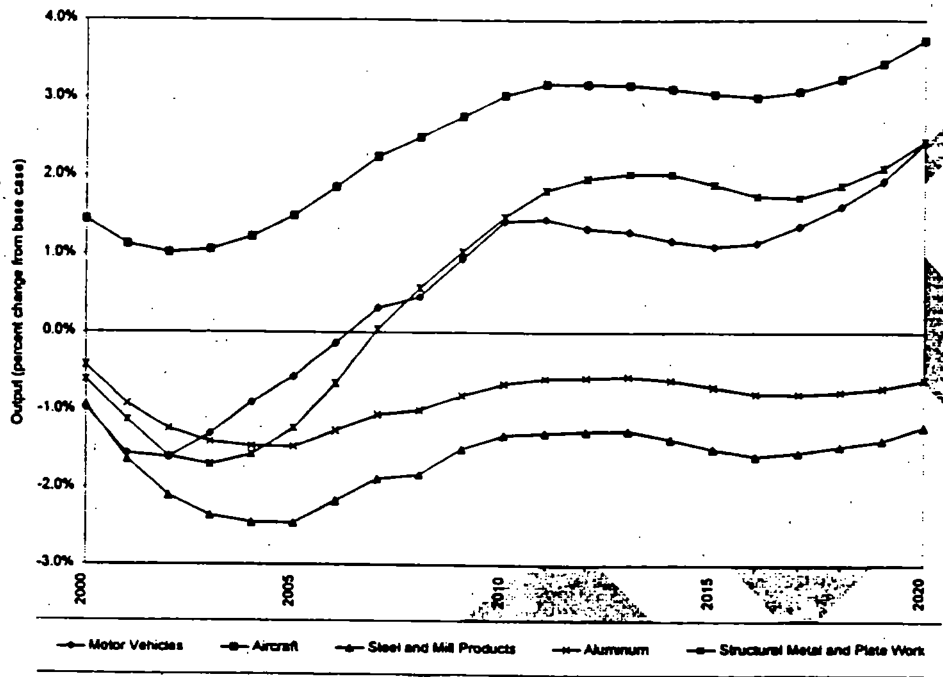
This mix effect is particularly and obviously important for energy producers. The DRI model suggests output of petroleum products will decline by 9 percent in 2010 and in 2020, when compared to the base case. As seen in Table 12, coal production in the United States will be 26 percent lower in 2010 and 39 percent lower in 2020 when compared to its projected levels in the base case.

Figure 27: DRI-DRI Energy 1990 Level Case, No International Trading--Output in Key Industries--New Construction, Mill and Wood Products, Veneer and Plywood, and Concrete and Gypsum



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Figure 28: DRI-DRI Energy 1990 Level Case, No International Trading--Output in Key Industries--Motor Vehicles, Steel and Mill Products, Structural Metal and Plate Work, Aircraft, Aluminum



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Mining (including coal, oil, and natural gas extraction) employment would be 6 percent and 7 percent lower, respectively, in 2010 and 2020: these declines are lower than output losses because productivity in the industry is generally anticipated to improve and the nation's coal mix is projected to shift to more productive coal reserves. These employment losses are particularly severe in the east and west south central regions.

Electric utilities experience smaller percentage reductions in output, but their losses are larger in dollar terms. Utility output declines by about $30 billion in 2010 and $52 billion in 2020 when compared to the base case. Petroleum refining and coal mining also experience larger losses than other energy-related industries on a dollar basis.

Table 12: DRI-DRI Energy 1990 Level Case, No International Trading Impacts on the Output of Selected Industries (percent change from the base case)

	2010	2020
Industries with the Largest Percent Increase in Output		
Aircraft	3.0	3.7
Truck Trailers	3.0	3.7
New Construction	2.8	5.4
Truck and Bus Bodies	2.7	3.5
Partitions and Fixtures	2.5	3.9
Lawn and Garden Equipment	2.3	3.3
Elevators and Materials Handling Equipment	2.3	2.8
Structural Metal Products	2.2	2.9
Concrete and Gypsum	2.1	4.3
Plumbing and Heating Equipment	2.1	4.0
Packaging Machinery	2.1	2.7
Industries with the Largest Percent Decline in Output*		
Rubber and Plastic Footwear	-10.3	-3.9
Nonferrous Metals	-3.2	-5.4
Household Audio and Video Equipment	-3.2	-6.1
Chemical and Fertilizer Mining	-3.1	-3.3
Watches and Clocks	-2.8	-4.9
Iron and Ferroalloy Ores	-2.6	-2.8
Other Leather Goods	-2.5	0.4
Nonferrous Wire and Cable	-2.5	-2.8
Misc. Nonferrous Ores	-2.3	-3.7
Industrial Organic and Inorg. Chemicals	-2.2	-2.1
Computers	-2.1	-6.1

Note: Emissions stabilized at 1990 levels in 2010. Revenues used for deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.
* Excluding energy producing sectors.

As discussed earlier, the DRI model found that the effect of a carbon-limiting policy on international trade is relatively small across all industries. However, as Table 13 shows, the trade impact on some specific industries are relatively large. For example, imports by the cement industry increase by 13 percent and exports are off by 3 percent, a net trade loss of 16 percent. Steel imports increase by almost 7 percent while its exports are cut by about 1 percent, a net trade loss of about 7 percent. On the other hand, fuel oil imports decline by about 39 percent, while exports increase by about 1 percent, a net trade gain of 40 percent. Imports for the industries listed in this table generally increase, while exports decline slightly.

**Table 13: DRI-DRI Energy, 1990 Level Case, No International Trading
Effects on Exports and Imports in 2010
(percent change from base case)**

	Imports	Exports
Paper and Allied Products		
Pulp Mills	0.9%	0.1%
Paper and Paperboard Mills	2.3%	-0.5%
Paperboard Boxes and Containers	1.6%	-0.2%
Paper Coating and Laminating	1.2%	0.1%
Sanitary Paper Products	0.8%	0.3%
Chemical and Allied Products		
Industrial Inorg. and Organic Chemicals	3.6%	-1.0%
Fertilizers	5.3%	-2.0%
Pesticides and Agr. Chemicals	0.2%	0.4%
Petroleum and Coal Products		
Petroleum Refining	-7.7%	0.5%
Fuel Oil	-38.6%	0.6%
Stone, Glass, and Clay Products		
Cement	13.3%	-2.8%
Concrete and Gypsum	5.3%	-0.2%
Cut Stone and Lime	7.4%	-1.1%
Primary Metals		
Steel and Mill Products	6.6%	-1.4%
Iron and Steel Foundries	2.7%	0.0%
Iron and Steel Forgings	3.6%	-0.1%
Aluminum	3.8%	-0.5%
Transportation Equipment		
Truck and Bus Bodies	3.4%	0.1%
Truck Trailers	4.7%	0.0%
Motor Vehicles	3.1%	-0.1%
Motor Vehicle Parts and Accessories	1.4%	-0.1%
Aircraft	3.0%	3.7%
Aircraft and Missile Engines and Parts	1.5%	2.5%
Computer and Electronic Equipment		
Computers	2.7%	-0.8%
Computer Peripheral Equipment	2.3%	-0.2%
Semiconductors	0.3%	-0.6%

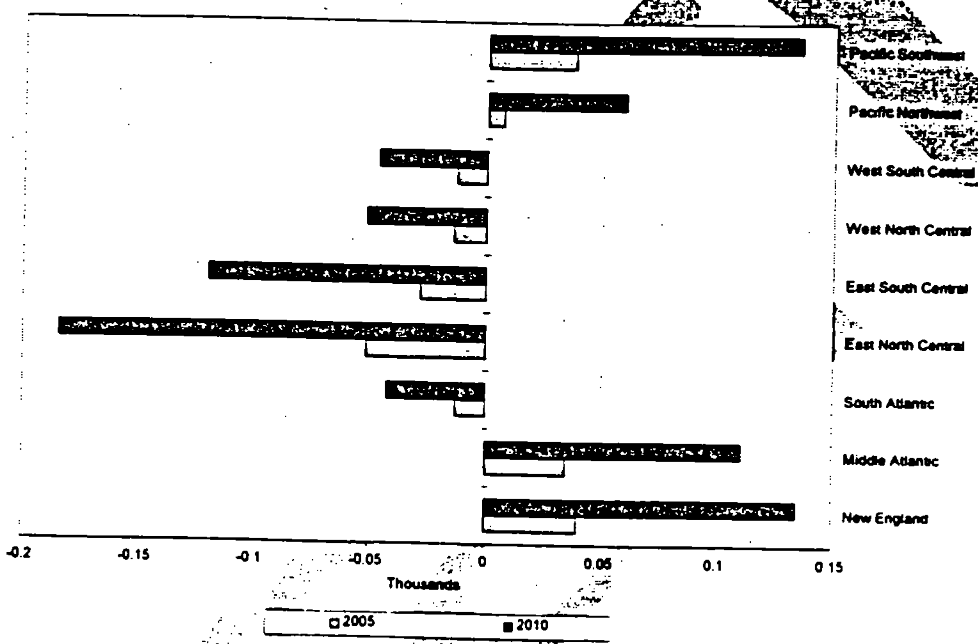
Note: Emissions stabilized at 1990 levels in 2010. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Regional and Employment Effects

The effects of climate change policy on the various regions of the country are shown in Table 14. In general, states in the East North Central, East South Central, and West North Central regions will have proportionally greater losses in population, 150-, 125-, and 75-thousand, respectively, nd employment, 210-, 165-, and 125-thousand, respectively, than the other regions of the country. See Figures 29 and 30. Total non-farm employment loss due to the climate change policy is about 900 thousand in 2005 compared with the baseline total non-farm employment of

135.3 million in that year. In 2010, total non-farm employment loss due to the climate change policy is only 400 thousand, compared with the baseline total non-farm employment of 140.9 million, as the economy starts to recover. The New England, Middle Atlantic, and the Pacific Southwest are expected to show long-term gains in population of 125-, 110-, and 130 thousand, respectively, and in employment of 125-, 45-, and 65-thousand, respectively, because of climate change policy implementation.

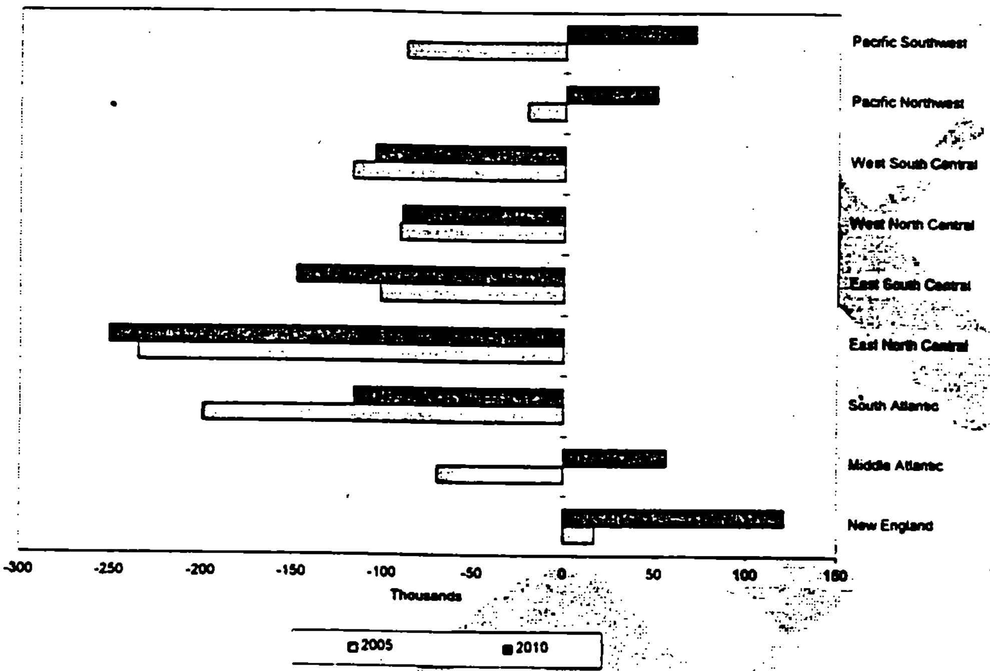
Figure 29: DRI-DRI Energy 1990 Level Case, No International Trading-- Population by Region (change from the base case)



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

The key to the regional effects relies on how revenue raised through permit sales is recycled to the economy. In the policy reviewed for regional effects, revenues are used to reduce the Federal budget deficit, which supports savings and, thus, increases investment. The climate change policy favors those states where production in industries support investment in structures and capital goods equipment, and of course, those areas of the country that are not as dependent on fossil fuel production. The climate change policy's effects are mitigated in those regions whose mix of industries favor investment goods industries and where the levels of industry production are large and can absorb the losses in production in industries that produce consumer goods.

Figure 30: DRI-DRI Energy 1990 Level Case, No International Trading--Total Non-Farm Employment by Region (change from the base case)



Note: Emissions stabilized at 1990 levels in 2010. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

As shown in Table 14, although the West South Central region is expected to have the greatest losses in fossil fuel employment, about 15 thousand in 2010, this represents only about 6 percent of its total mining employment in that year. On the other hand, the East South Central Region is expected to lose about 8 thousand in 2010, but this represents about 22 percent of its total fossil fuel employment in the same year.

Table 14: DRI-DRI Energy 1990 Level Case, No International Trading Regional Impacts

Year	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Pacific North-west	Pacific Southwest
Disposable Income, % change from the base case									
2005	0.9	0.4	-0.1	-0.4	-0.5	-0.7	-0.2	0.3	0.3
2010	1.9	0.7	-0.1	-1.1	-1.3	-1.2	-0.4	1.1	0.6
2020	2.9	0.9	0.1	-1.4	-1.5	-1.9	-0.7	1.4	0.7
Total Non-farm employment, % change from the base case									
2005	0.3	-0.4	-0.8	-1.0	-1.3	-0.9	-0.8	-0.4	-0.4
2010	1.7	0.3	-0.4	-1.1	-1.8	-0.8	-0.7	0.8	0.3
2020	2.7	0.5	-0.2	-1.1	-1.7	-0.9	-0.8	1.1	0.5%
Mining, Oil, and Gas Employment, % change from the base case									
2005	0.4	-8.5	-8.3	-5.9	-10.9	-0.8	-1.4	-2.1	-0.9
2010	4.4	-10.9	-11.6	-7.8	-20.5	1.0	-6.4	-1.1	0.8
2020	9.0	-14.0	-15.6	-6.2	-27.8	4.3	-4.8	-8.3	0.6
Population, change from the base case (millions)									
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.1	0.1	0.0	-0.2	-0.1	-0.1	-0.1	0.1	0.1
2020	0.3	0.2	0.0	-0.3	-0.2	-0.1	-0.1	0.1	0.2
Manufacturing Employment, change from the base case (thousands)									
2005	9.6	1.7	-32.5	-77.1	-24.7	-19.5	-21.5	-1.0	-0.6
2010	26.5	21.7	-28.4	-116.1	-32.5	-28.3	-28.5	6.7	17.3
2020	36.9	13.9	-33.8	-142.5	-32.7	-35.3	-41.8	7.3	23.9
Transportation, Communication & Utilities, change from the base case (thousands)									
2005	1.7	-4.1	-12.1	-15.5	-4.9	-8.1	-8.7	-1.6	-6.5
2010	5.7	-2.9	-16.5	-25.9	-9.4	-13.5	-14.9	0.3	-5.5
2020	8.4	-4.8	-18.1	-31.8	-10.0	-16.1	-17.9	0.4	-5.4

Note: Emissions stabilized at 1990 levels in 2010. Revenues used for Federal deficit reduction and assuming a 1.25 percent annual decrease in E/GDP.

Appendix Table A: Assumptions Regarding Non-Carbon Greenhouse Gases (million metric tons of carbon equivalent)

	1900	1995	2000	2005	2010	2015	2020
Baseline Emissions							
CH4	169	178	150	152	152	154	155
HFC PFC	24	n/a	42	69	91	115	133
N2O	37	34	31	32	34	36	37
Sinks	-136	-128	-121	-120	-119	-111	-103
Total	95	n/a	102	133	158	194	223
Cost Effective Reductions in Emissions (assuming an implicit price of carbon of $70 per ton)							
CH4					27	29	29
HFC PFC					51	75	110
N2O					4	[illegible]	4
Sinks				7	15	15	15
Total Reduction					97	123	159
Emissions with Cost Effective Reductions							
CH4	169	178	150	152	125	126	126
HFC PFC	24	n/a	42	69	40	41	23
N2O	37	34	31	32	30	31	33
Sinks	-136	-128	-121	-120	-134	-126	-118
Total Other Gas Emissions	95	n/a	102	133	61	71	64
Reductions Below 1990 Levels					34	23	31

Note: Million metric ton of carbon equivalent calculated using 100 year Global Warming Potentials (GWP) (IPCC, 1995). The $70 per ton cit price of carbon was an estimate used by the IAT prior to generating implicit price of carbon using the IAT models.

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Divider Title: M

Draft Protocol to the Framework Convention on Climate Change

As released by the Department of State, Bureau of Oceans and International Environmental and Scientific Affairs, January 28, 1997.

January 17, 1997

U.S. DRAFT PROTOCOL FRAMEWORK
(submitted without prejudice to ultimate form of agreement)

The Parties to this Protocol,

Have agreed as follows:

Article 1
Definitions

For purposes of this Protocol:

1. "The Convention" means the United Nations Framework Convention on Climate Change done at New York on 9 May 1992.

2. "Party" means Party to this Protocol.

3. "Greenhouse gas" means any greenhouse gas for which a global warming potential is set forth in Annex C of this Protocol.

4. "Tonne of carbon equivalent" means one metric tonne of carbon, or a quantity of one or more other greenhouse gases equivalent to one metric tonne based on the global warming potentials set forth in Annex C of this Protocol.

5. "Net anthropogenic emissions" of greenhouse gases is the calculated difference between emissions by sources and removals by sinks.

6. [other definitions to be developed or cross-referenced to the Convention as necessary]

Article 2
Emissions Budgets

1. Each Annex A and Annex B Party shall ensure that its net anthropogenic emissions of greenhouse gases do not exceed its emissions budget for any applicable budget period, as specified in this Article.

2. For each Annex A and Annex B Party, its emissions budget shall be denominated in tonnes of carbon equivalent emissions allowed and shall equal:

(a) the tonnes of carbon equivalent emissions it is allowed under paragraph 3 or 4 below, plus
(b) any tonnes of carbon equivalent emissions allowed that are carried over from a prior

budget period under paragraph 5 below, plus
(c) up to [percent] of the tonnes of carbon equivalent emissions allowed under paragraph 3 or 4 below, such as may be borrowed from the subsequent budget period under paragraph 6 below, plus
(d) any tonnes of carbon equivalent emissions allowed that are acquired from another Party under Article 6 (International Emissions Trading) or Article 7 (Joint Implementation), minus
(e) any tonnes of carbon equivalent emissions allowed that are transferred to another Party under Article 6 (International Emissions Trading).

3.

1. (a) For the first budget period, [20 through 20], each Annex A Party shall have a number of tonnes of carbon equivalent allowed equal to [a percentage of] its net anthropogenic emissions of tonnes of carbon equivalent in 1990, multiplied by [the number of years in this budget period].
(b) For the second budget period, [20 through 20], each Annex A Party shall have a number of tonnes of carbon equivalent emissions allowed equal to [a percentage equal to or less than the percentage in subparagraph 3(a)] of its net anthropogenic emissions of tonnes of carbon equivalent in 1990, multiplied by [the number of years in this budget period].
(c) [possible subsequent budget period(s)]

4. For the budget period [20 through 20], each Annex B Party (see Annex B for States included) shall have a number of tonnes of carbon equivalent emissions allowed equal to [options for Annex B Parties include: budget periods, baseyears, and/or percentages different from those applicable to Annex A Parties].

5. At the end of a budget period applicable to a Party, any amount by which the Party's emissions of tonnes of carbon equivalent is under its emissions budget for that period may be carried over and added to its emissions budget for the next budget period.

6. At the end of a budget period applicable to a Party, any amount of tonnes of carbon equivalent emissions allowed that is borrowed from the subsequent budget period shall be subtracted at a rate of [1.2:1] from the subsequent budget period.

7. [Provision requiring control of greenhouse gases not listed in Annex C.]

8. Any State not listed in Annex A may, in its instrument of ratification, acceptance, approval or accession, or at any time thereafter, notify the Depositary that it intends to be bound by obligations of Annex A Parties. It will then be an Annex A Party. The Depositary shall inform the other signatories and Parties of any such notification.

9. Any State not listed in Annex A may, in its instrument of ratification, acceptance, approval, or accession, or at any time thereafter, notify the Depositary that it intends to be bound by obligations of Annex B Parties. It will then be an Annex B Party. The Depositary shall inform the other signatories and Parties of any such notification.

Article 3
Measurement and Reporting

1. Each Annex A and Annex B Party shall have in place by [the first year of its first budget period] a national system for the accurate measurement of anthropogenic emissions by sources, and removals by sinks, of greenhouse gases.

2. For the purposes of implementing paragraph 1 and promoting comparability, consistency, and transparency, the Parties shall, not later than their second Meeting, decide on minimum standards for the measurement of anthropogenic emissions by sources, and removals by sinks, of greenhouse gases.

3. Each Annex A and Annex B Party shall put in place, if it has not already done so, national compliance and enforcement programs relevant to its implementation of the obligations under this Protocol.

4. Each Annex A and Annex B Party shall submit to the Secretariat, as part of its communication under Article 12 of the Convention, information on its implementation of this Protocol, including policies and measures it is taking to meet its obligations in Article 2. Such submission shall be in accordance with guidelines which the Parties adopt at their first Meeting, taking into account any relevant guidelines adopted by the Parties to the Convention. Such submission shall also contain the following information:

(a) once the obligation in paragraph 1 above becomes effective, a description of the national measurement system that it has in place;

(b) once the obligation in paragraph 1 above becomes effective, the results of its national measurement system;

(c) a quantitative projection of its net anthropogenic emissions of greenhouse gases through the budget periods; and

(d) a description of relevant national compliance and enforcement programs it has in place pursuant to paragraph 3 above, as well as a description of their effectiveness, including actions taken in cases of non-compliance with national law.

5. In addition to the information required to be submitted under paragraph 4, each Annex A and Annex B Party shall submit to the Secretariat, on an annual basis and in accordance with the guidelines referred to in paragraph 4, its current calculation corresponding to each of the subparagraphs in Article 2.2 and its remaining emissions budget for that budget period. With respect to any tonnes of carbon equivalent emissions allowed that are acquired or transferred under Articles 6 or 7, the Party shall specify the quantity, Party of origin or destination, and the relevant budget period.

6. The first of the submissions referred to in paragraph 5 shall be part of a Party's first communication that is due after the Protocol has been in force for that Party for two years. The frequency of subsequent submissions shall be determined by the Parties.

7. Information communicated by Parties under this Article shall be transmitted by the secretariat as soon as possible to the Parties and to any subsidiary bodies concerned.

8. Without prejudice to the ability of any Party to make public its communication at any time, the secretariat shall make information communicated by Parties under this Article publicly available at the time it is submitted to the Parties.

Article 4
Review and Compliance Process

1. In addition to the review of communications conducted under Article 10.2(b) of the Convention, the Meeting of the Parties shall consider the information submitted by Annex A and Annex B Parties under Article 3 in order to assess those Parties' implementation of their obligations.

2. Reviews will be conducted by expert review teams, which will be coordinated by the secretariat and composed of experts selected from those nominated by Parties and, as appropriate, by intergovernmental organizations.

3. Reviews will be in accordance with guidelines to be adopted by the Meeting of the Parties. These guidelines shall, inter alia, provide for how information will be made available to the public and define mechanisms by which observers and the public may

provide comments, supplemental data or other information to facilitate and improve reviews. The guidelines shall be periodically reviewed by the Parties for appropriate revision.

4. Review teams will review all aspects of a Party's implementation of this Protocol, including the likelihood that a Party will achieve its emissions budgets obligations. They will prepare a report assessing a Party's implementation of its obligations, identifying any areas of apparent non-compliance, as well as potential problems in achieving obligations. Reports will be provided to a Meeting of the Parties.

5. Based on such reports, a Meeting of the Parties may make recommendations to a Party. In such case, the Party shall review its implementation, take appropriate action, and report back to the next Meeting of the Parties on its action.

6. There would also be provisions setting forth various consequences for non-compliance with obligations, as determined by a Meeting of the Parties. Consequences would correspond to the type, degree, and frequency of non-compliance. Some would be automatic, while others might be discretionary. Examples of consequences could include, e.g.:

(a) denial of the opportunity to sell tonnes of carbon equivalent emissions allowed through international emissions trading and/or joint implementation;

(b) loss of voting rights and/or other opportunities to participate in processes under the Protocol.

Article 5
Advancement of the Implementation of
Article 4.1 of the Convention

Recognizing the progress that has been made to date in implementing commitments under Article 4.1 of the Convention:

1. The Parties reaffirm their commitments under Article 4.1 of the Convention and the need to continue to advance the implementation of such commitments.

2. Each Party shall strengthen its legal and institutional framework to advance the implementation of its commitments under Article 4.1 of the Convention.

3. Each Party shall take measures to facilitate investment in climate-friendly technologies.

4. Each Party shall report, as part of its communication under the Convention, on how it is promoting public education and participation in the development of climate change policy.

5. Each Party that is neither in Annex A nor Annex B shall identify and implement "no-regrets" measures for mitigating net anthropogenic emissions of greenhouse gases, including any identified through the review process under paragraph 7 below. In this regard, each such Party shall also:

(a) quantify the effects of the measures it implements;
(b) evaluate barriers to the adoption of potential measures; and
(c) report to the Secretariat, as part of its communication under the Convention, on the measures it has implemented, plans to implement, and barriers to the adoption of potential measures.

6. Each Party that is neither in Annex A nor Annex B shall submit to the Secretariat, on an annual basis, its inventory of greenhouse gas emissions. Such inventory shall be consistent with any guidelines adopted by the Parties.

7. The Parties shall establish a process for reviewing communications received under the Convention from the Parties identified in paragraphs 5 and 6. The process shall be designed to:

(a) enable the review of the effects of individual measures described in paragraph 5;
(b) assist such Parties in identifying and implementing "no-regrets" measures for mitigating net anthropogenic emissions of greenhouse gases;
(c) seek to identify key sectors and technological options within them;
(d) consider possibilities for promoting voluntary arrangements with industry aimed at identifying and encouraging implementation of "no regrets" measures; and
(e) explore various means through which such Parties could obtain both the know-how and the technology needed to implement options identified.

Article 6
International Emissions Trading

1. An Annex A or Annex B Party that is in compliance with its obligations under Article 3 (Measurement and Reporting) and that has in place a national mechanism for certification and verification of trades, may transfer to, or receive from, any Annex A or Annex B Party, any of its tonnes of carbon equivalent emissions allowed for a budget period, for the purpose of meeting its obligations under Article 2.

2. A Party may authorize any domestic entity (e.g., government agencies, private firms, non-governmental organizations, individuals) to participate in actions leading to transfer and receipt under paragraph 1 of tonnes of carbon equivalent emissions allowed.

3. A Meeting of the Parties may further elaborate guidelines to facilitate the reporting of emissions trading information.

Article 7
Joint Implementation

1. Any Party that is neither in Annex A nor B may generate tonnes of carbon equivalent emissions allowed through projects that meet the criteria set forth in paragraph 2.

2. In addition to any criteria adopted by the Parties to this Protocol, the following criteria shall apply to projects:

(a) Projects must be compatible with and supportive of national environment and development priorities and strategies, as well as contribute to cost-effectiveness in achieving global benefits;

(b) Projects must provide a reduction in emissions that is additional to any that would otherwise occur.

3. [Additional provisions to be added on calculation, measurement, monitoring, verification, review, reporting]

4. Any Party that generates tonnes of carbon equivalent emissions allowed consistent with this Article may:

(a) hold such tonnes of carbon equivalent emissions allowed; or
(b) transfer any portion thereof to any Party.

5. An Annex A or Annex B Party may acquire tonnes of carbon equivalent emissions allowed under this Article for the purpose of meeting its obligations under Article 2. provided it is in compliance with its obligations under Article 3 (Measurement and

Reporting).

6. A Party may authorize any domestic entity (e.g., government agencies, private firms, non-governmental organizations, individuals) to participate in actions leading to generation, transfer and receipt under this Article of tonnes of carbon equivalent emissions.

7. Any Party that is neither in Annex A nor Annex B that generates or acquires tonnes of carbon equivalent emissions allowed under this Article shall notify the Secretariat annually of the quantity, origin, and destination of such tonnes.

Article 8
Science

The Parties shall periodically review this Protocol, and guidelines established thereunder, in light of evolving scientific knowledge related to climate change.

Article 9
Progress Toward Long-Term Goal

The Parties shall cooperate in the establishment of a long-term goal with respect to atmospheric concentrations of greenhouse gases.

Article 10
Meetings of the Parties

1. The Parties shall hold meetings at regular intervals. The secretariat shall convene the first meeting of the Parties not later than one year after the date of the entry into force of this Protocol and in conjunction with a meeting of the Conference of the Parties to the Convention.

2. Subsequent meetings of the Parties shall be held, unless the Parties decide otherwise, in conjunction with meetings of the Conference of the Parties to the Convention. Extraordinary meetings of the Parties shall be held at such other times as may be deemed necessary by a meeting of the Parties, or at the written request of a Party, provided that within six months of such a request being communicated to them by the secretariat, it is supported by at least one third of the Parties.

3. The Parties, at their first meeting, shall:

(a) adopt, by consensus, rules of procedure for their meetings;
(b) [other].

4. The functions of the meetings of the Parties shall be to:

(a) review the implementation of this Protocol, including the information submitted in accordance with Article 3;
(b) periodically review the adequacy of this Protocol;
(c) [other].

5. The United Nations, its specialized agencies and the International Atomic Energy Agency, as well as any State not party to this Protocol, may be represented at meetings of the Parties as observers. Any body or agency, whether national or international, governmental or non-governmental, qualified in fields relating to climate change which has informed the secretariat of its wish to be represented at a meeting of the Parties as an observer may be admitted unless at least one third of the Parties present object. The admission and participation of observers shall be subject to the rules of procedure adopted by the Parties.

Article 11
Secretariat

1. In accordance with Article 8.2(g) of the Convention, the secretariat of this Protocol shall be the secretariat of the Convention.

2. The functions of the secretariat shall be:

(a) ...

Article 12
Subsidiary Body for Scientific and Technological Advice

1. The Subsidiary Body for Scientific and Technological Advice of the Convention shall serve as the Subsidiary Body for Scientific and Technological Advice of the Protocol.

2. When the Subsidiary Body for Scientific and Technological Advice exercises its functions with regard to matters concerning the Protocol, decisions shall be taken only by those of its members that are, at the same time, Parties to the Protocol.

3. When the Subsidiary Body for Scientific and Technological Advice exercises its functions with regard to matters concerning the Protocol, any member of the bureau of the Subsidiary Body for Scientific and Technological Advice representing a Party to the Convention, but, at the same time, not a Party to the Protocol, shall be substituted by an additional member to be elected by and from the Parties to the Protocol.

Article 13
Subsidiary Body for Implementation

1. The Subsidiary Body for Implementation of the Convention shall serve as the Subsidiary Body for Implementation of the Protocol.

2. When the Subsidiary Body for Implementation exercises its functions with regard to matters concerning the Protocol, decisions shall be taken only by those of its members that are, at the same time, Parties to the Protocol.

3. When the Subsidiary Body for Implementation exercises its functions with regard to matters concerning the Protocol, any member of the bureau of the Subsidiary Body for Implementation representing a Party to the Convention, but, at the same time, not a Party to the Protocol, shall be substituted by an additional member to be elected by and from the Parties to the Protocol.

Article 14
Multilateral Consultative Process

[The Parties, at their first Meeting or as soon as practicable thereafter, shall consider the establishment of a multilateral consultative process to promote effective implementation of the Convention.]

Article 15
Dispute Settlement

[silence, with the result that Article 14 of the Convention would apply to this Protocol.]

[in addition, mandatory, binding dispute settlement [with specific consequences flowing from a violation] among Annex A and Annex B Parties, as well as against other Parties as appropriate (e.g., host countries under Article 7)]

Note: this process would be without prejudice to the review and compliance process under Article 4

Article 16
Evolution

The Parties shall adopt, by [2005], binding provisions so that all Parties have quantitative greenhouse gas emissions obligations and so that there is a mechanism for automatic application of progressive greenhouse gas emissions obligations to Parties, based upon agreed criteria.

Views on Certain Final Clauses

Adoption and Amendments of Annexes

Depending upon what type of material is eventually included in annexes, it may not be appropriate to restrict the content of all annexes to "lists, forms and any other material of a descriptive nature that is of a scientific, technical, procedural or administrative character." For any substantive annex, it may not be appropriate to provide for tacit adoption/amendment.

Signature

This provision should state that only Parties to the Convention may be Parties to the Protocol.

Entry into Force

To ensure effective implementation, as well as to minimize the potential "free rider" problem, this provision may need to stipulate an entry into force trigger that requires ratification by States that account for a particular percentage of global emissions of greenhouse gases.

Annex A

This Annex would include the same States as those listed in Annex I of the Convention, plus those that join subsequently pursuant to Article 2.

Annex B

This Annex would include those States not listed in Annex A that indicate before adoption of the protocol that they want to be included in this Annex, plus those that join subsequently pursuant to Article 2.

Annex C

This Annex would list greenhouse gases not covered by the Montreal Protocol, with the exception of gases, or particular sources and sinks, for which there is insufficient knowledge of the GWP or inability to accurately measure emissions or removals. GWPs would be those developed by the IPCC.

[end of document]

FACT SHEET ON SUPPLEMENTAL U.S. CLIMATE CHANGE PROPOSALS

June 1997

In January 1997 the United States submitted a draft text for a legal instrument to address next steps under the United Nations Framework Convention on Climate Change. Several technical elements left undefined in the January submission (principally those relating to compliance issues, and to which gases should be included in an agreement) have been further developed in the attached text; they are described below. The revised U.S. draft protocol proposal containing these new elements will form the basis for the U.S. position in the next session of the Ad Hoc Group on the Berlin Mandate (scheduled to meet in late July). Please call Jonathan Pershing (647-4069) or Linda Strachan (647-3550) of the State Department with any questions.

COMPLIANCE

- The January text created "emissions budgets", with targets based on the total emissions over a period of several years; this revision provides for a penalty to be assessed should a Party exceed its allowed budget.

- The January text created a review process; this revision calls for the review process to build on the existing Convention review mechanism, authorizes the review of any pertinent information, allows for consultations with both the Party and others in the course of a review, calls for the circulation of the completed review to all Parties, and requests the Secretariat to identify any report that requires further consideration.

- The January text provided an option for Parties with budgets to trade emissions; this text limits trading to Parties that have met all obligations pertaining to measurement and reporting of budgets, and that have in place national mechanisms for certification and verification of trades. With respect to a given budget period, it also precludes a Party from trading if it has exceeded its budget, and provisionally limits a Party's ability to trade if its compliance has been called into question.

- The January text provided for Meetings of the Parties; this text also calls for periodic review by the Parties of protocol implementation (including of the review process), requires Parties to implement an appropriate non-compliance regime (including through the development of an indicative list of consequences for non-compliance), and allows the Parties to establish an implementation committee to assist them in carrying out these duties.

ANNEX C: WHICH GASES ARE INCLUDED

- The January text suggested that all gases for which monitoring and measurement procedures are available should be included in the agreement; this revision maintains the broad inclusion of all greenhouse gases, sources, sinks and sectors, and calls upon the Parties to decide on best available methods for measurement, and to propose adjustments to the measurements in cases where best available methods are not used. The revision also calls for periodic updating of measurement methods.

Additional U.S. Proposals
(references are to the original U.S. submission)

Article 1 (Definitions)

- Replace definition 3 ("Greenhouse gas") with the following:

  "Greenhouse gas" means any greenhouse gas covered in Annex C of this Protocol."

- Replace definition 4 ("Tonne of carbon equivalent") with the following:

  "Tonne of carbon equivalent" means one metric tonne of carbon, or a quantity of one or more other greenhouse gases equivalent to one metric tonne based on the global warming potentials decided by the Parties in accordance with Annex C of this Protocol.

Article 2 (Emissions Budgets)

- Delete paragraph 7

Article 3 (Measurement and Reporting)

- Replace paragraph 2 with the following:

  For the purposes of implementing paragraph 1 and promoting comparability, consistency, and transparency, the Parties shall, not later than their first Meeting, decide on agreed best available methods for the measurement by Parties of anthropogenic emissions by sources, and removals by sinks, of greenhouse gases, taking into account the best available methods determined by the IPCC and other expert bodies. They shall also decide on appropriate adjustments to measurements of emissions and removals where agreed best available methods have not been used. The Parties shall periodically update agreed best available methods and adjustments based on evolving scientific knowledge, including advice from the Subsidiary Body for Scientific and Technological Advice referred to in Article 12.

Annex C

- Replace descriptive language with the following:

  All greenhouse gases, their sources and sinks, with global warming potentials as decided by the Parties at their first meeting (taking into account the IPCC's global warming potentials for 100-year time horizons) and as subsequently updated by the Parties to reflect evolving scientific knowledge.

Additional U.S. Proposals
(references are to the original U.S. submission)

In Article 2 of the U.S. proposal (Emissions Budgets), add a new paragraph 6.bis. as follows:

2.6.bis. At the end of a budget period applicable to a Party, any amount of tonnes of carbon equivalent emissions over its emissions budget shall be subtracted at a rate of [rate greater than that in paragraph 6] from the subsequent budget period.

In Article 4 of the U.S. proposal (Review and Compliance Process), substitute for paragraphs 3 to 6 the following text:

4.3 Reviews will be in connection with the review of communications conducted under Article 10.2(b) of the Convention and will be in accordance with guidelines to be adopted by the Parties at a meeting. These guidelines shall, inter alia, provide for how information will be made available to the public and define mechanisms by which observers and the public may provide comments, supplemental data or other information to facilitate and improve reviews. The guidelines shall be periodically reviewed by the Parties for appropriate revision.

4.4 Review teams will review all aspects of a Party's implementation of this Protocol, including the likelihood that a Party will achieve its emissions budgets obligations. They will be authorized, inter alia, to review pertinent information and consult with the Party in question and others as necessary. They will prepare a report assessing a Party's implementation of its obligations, identifying any areas of apparent non-compliance, as well as potential problems in achieving obligations.

4.5 Such reports will be circulated by the Secretariat to all Parties. In addition, the Secretariat will identify for further consideration any report indicating a question of implementation.

In Article 6 of the U.S. proposal (International Emissions Trading), substitute the following text:

6.1. Except as otherwise provided below, any Annex A or Annex B Party may transfer to, or acquire from, any Annex A or Annex B Party, any of its tonnes of carbon equivalent emissions allowed for a budget period, for the purpose of meeting its obligations under Article 2.

6.2 An Annex A or Annex B Party may not transfer or acquire any of its tonnes of carbon equivalent emissions allowed if it is not in compliance with its obligations under Article 3 (Measurement and Reporting) or if it does not have in place a national mechanism for certification and verification of trades.

6.3 An Annex A or Annex B Party may not transfer in a given budget period any of its tonnes of carbon equivalent emissions allowed if it has exceeded its emissions budget for that period.

6.4 If a question of a Party's implementation of the requirements referred to in paragraph 2 or 3 above is identified by either the review process under Article 4.5 or by the Secretariat under Article 11.2(b):

-- transfers and acquisitions of tonnes allowed (in the case of paragraph 2) and transfers of tonnes allowed (in the case of paragraph 3) may continue to be made after the question has been identified, provided that any such tonnes may not be used by any Party to meet its obligations under Article 2 until any issue of compliance is resolved. Issues of compliance shall be resolved as expeditiously as possible.

6.5 A Party may authorize any domestic entity (e.g., government agencies, private firms, non-governmental organizations, individuals) to participate in actions leading to transfer and acquisition under paragraph 1 of tonnes of carbon equivalent emissions allowed.

6.6 The Parties, at a meeting, may further elaborate guidelines to facilitate the reporting of emissions trading information.

In Article 10 of the U.S. proposal (Meetings of the Parties), for paragraph 4, substitute the following text:

10.4 The Parties:

(a) shall periodically review the adequacy of this Protocol;

(b) shall review the implementation of this Protocol, including the information submitted in accordance with Articles 3 and 5, reports received from the review teams referred to in Article 4, and any other reports and recommendations received from processes under this Protocol;

(c) shall implement an appropriate regime to address cases of non-compliance with obligations under this Protocol, including through the development of an indicative list of consequences, taking into account the type, degree, and frequency of non-compliance;

(d) may establish an implementation committee consisting of a subset of Parties to assist them, including by making recommendations, in carrying out functions referred to in subparagraphs (b) and (c) above.

In Article 11 of the U.S. proposal (Secretariat), for paragraph 2, substitute the following:

11.2 The functions of the secretariat shall be:

(a) to maintain and administer records relating to the accounting of the emissions budgets of Annex A and Annex B Parties, including initial budget allocations, adjustments to budgets consistent with Articles 2, 6, and 7, annual emissions, and remaining budgets in a given budget period;

(b) to facilitate the review of implementation of this Protocol through, inter alia, coordinating the review of Annex A and Annex B implementation; coordinating the reviews under Article 5; identifying for the Parties questions of implementation, including whether individual reports are consistent with reporting criteria; and preparing an annual compilation and synthesis report that contains inventory and budget information, and notes any discrepancies in accounting.

(c) [other].

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